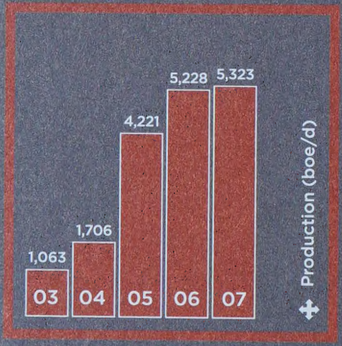
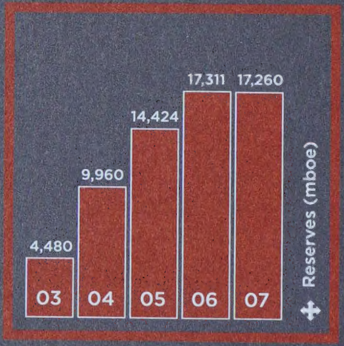
STRATEGY EXECUTION RESULTS

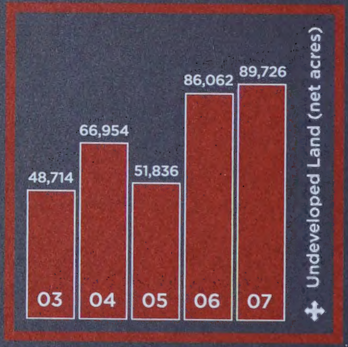
DELPHI ENERGY CORP.
ANNUAL REPORT 2007

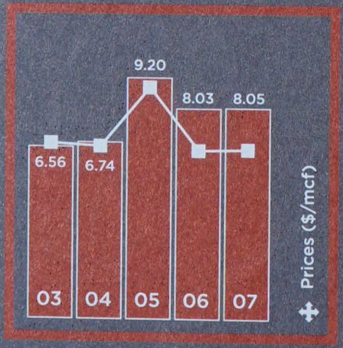
highlights 01
our message to shareholders 06
operations review 10
operational statistics 18
management discussion and analysis 23
financial statements 45
notes to financial statements 49
corporate information 60



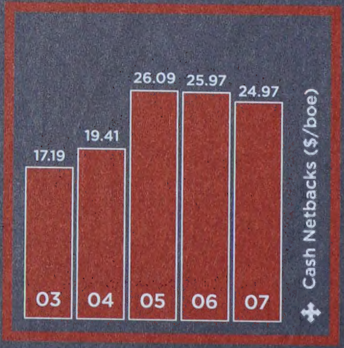
Production (boe/d)

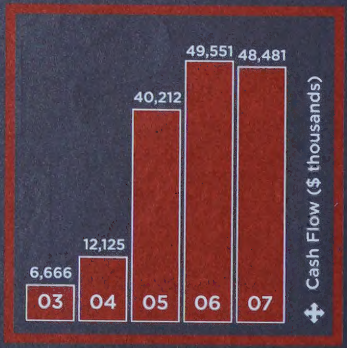






Realized Gas Price ($/mcf)
AECO ($/mcf)





Year ended December 31	2007	2006
FINANCIAL HIGHLIGHTS		
($ thousands except per unit amounts)		
Gross petroleum and natural gas sales	**97,933**	94,189
Per boe	**50.41**	49.36
Funds from operations	**48,481**	49,551
Per boe	**24.97**	25.97
Per share - Basic	**0.72**	0.85
- Diluted	**0.72**	0.84
Net earnings (loss)	**(10,472)**	6,903
Per boe	**(5.38)**	3.62
Per share - Basic	**(0.16)**	0.12
- Diluted	**(0.16)**	0.12
Capital invested	**62,795**	165,352
Proceeds on dispositions	**(15,502)**	(34,918)
Net capital	**47,293**	130,434
Debt plus working capital deficit	**100,658**	118,178
Total assets	**311,735**	326,668
Shares outstanding (thousands)		
Basic	**68,070**	60,663
Diluted	**73,550**	64,892
OPERATING HIGHLIGHTS		
Average daily production		
Natural gas (mcf/d)	**26,886**	25,706
Percentage of total production	**84%**	82%
Oil and natural gas liquids (bbls/d)	**842**	944
Percentage of total production	**16%**	18%
Total (boe/d)	**5,323**	5,228
Realized selling prices		
Natural gas ($/mcf)	**8.05**	8.03
Oil ($/bbl)	**61.28**	53.19
Natural gas liquids ($/bbl)	**62.28**	56.25
Total oil equivalent ($boe)	**50.41**	49.36
Wells drilled (net)	**8.1**	21.7
Undeveloped land		
Gross acres	**251,963**	274,581
Net acres	**89,726**	86,062
Average working interest (%)	**36%**	31%
Proved plus probable reserves (P+P)		
Natural gas (mmcf)	**91,108**	85,116
Oil and natural gas liquids (mbbls)	**2,076**	3,125
Total oil equivalent (mboe)	**17,260**	17,31
Finding and development costs (P+P)	**13.11**	32.24
Finding, development and acquisition (P+P)	**21.49**	32.04
Reserve life index (P+P)	**8.9**	9.1

HOW WE'VE DONE

GROWTH:

Production
Reserves
Shareholder Value

OPPORTUNITY:

Drilling Locations
Undeveloped Land
Long Term Visibility

FINANCIAL STRENGTH:

Cash Flow
Risk Management
Capital Flexibility

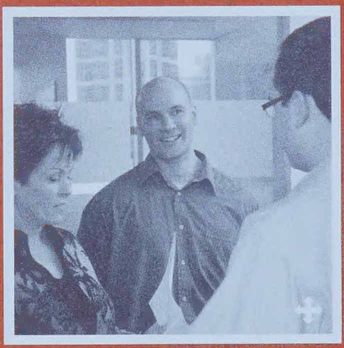
STRATEGY

STRATEGY. EXECUTION. RESULTS.

DELPHI ENERGY CORP. ("DELPHI" OR "THE COMPANY") ENJOYED SIGNIFICANT SUCCESS IN 2007, IN AN ENVIRONMENT OF WEAK AND VOLATILE NATURAL GAS PRICES. THE COMPANY ACHIEVED ITS GOALS OF DELIVERING MEASURABLE GROWTH, INCREASING FINANCIAL FLEXIBILITY AND ENSURING THE COMPANY REMAINS WELL POSITIONED FOR SUSTAINABLE ORGANIC GROWTH.

CORPORATE PROFILE

The Company achieved record production during the fourth quarter 2007, averaging 5,868 barrels of oil equivalent per day (84 percent natural gas), up 18 percent from the comparative quarter in 2006, while spending less than cash flow through 2007. Financial flexibility improved significantly during 2007 decreasing net debt by 15 percent from the beginning of the year to $100.7 million at December 31, 2007. The Company has never been in a better position to deliver long term growth. The Hythe/Bigfoot swap and Noel and Red Rock joint ventures were all completed during 2007. The drilling success in 2007 and the recent downspacing approval at Bigstone have also contributed to positioning the Company for sustainable long term organic growth.



Delphi maintains a competitive advantage within its core areas with operatorship and control of over 80 percent of its production, field gathering and processing infrastructure. During 2007, the Company operated over 95 percent of its capital program. The Company's producing assets can be characterized as natural gas focused with medium to long life deep basin production profiles, and a low cost structure resulting in superior economic netbacks and recycle ratios.

WHO WE ARE

OUR MESSAGE TO SHAREHOLDERS

Delphi enjoyed a successful 2007, in an environment of weak and volatile natural gas prices, accomplishing its goals of delivering measurable growth, increasing financial flexibility and ensuring the Company remains well positioned for long term organic growth in any business environment.

The Company achieved record production during the fourth quarter of 2007 averaging 5,868 barrels of oil equivalent per day, up 18 percent from the comparative quarter in 2006 while spending less than funds from operations (cash flow) through 2007.

Financial flexibility improved significantly during 2007. Net debt decreased 15 percent from the beginning of the year to $100.7 million at December 31, 2007. The combination of cash flow growth and debt reduction has improved the debt to cash flow ratio to approximately 1.8 at December 31, 2007.

The Company has never been in a better position to deliver long term growth. The Hythe/ Bigfoot swap and Noel and Red Rock joint ventures were all completed during 2007.

The drilling success in 2007 and the recent downspacing approval at Bigstone have also contributed to positioning the Company for sustainable long term organic growth.

Year in Review

The Company executed its 2007 capital program as planned. The development program was refocused on Delphi's large inventory of robust conventional growth opportunities. The Company chose to defer expenditures on its the Bigfoot, British Columbia resource play where profitability is much more sensitive to natural gas prices and development costs. In September 2007, Delphi swapped Bigfoot for conventional assets in the Hythe area in Alberta. The Company successfully deployed exploration capital in its new areas at Noel, British Columbia and Red Rock, Alberta. Capital was also allocated to the acquisition of an additional 10.5 percent working interest in the Company's prolific Tower Creek Leduc well, currently producing 23 million cubic feet per day of sour gas (approximately 800 boe/d net).

Delphi maintains a competitive advantage within its core areas as operator, controlling more than 80 percent of its production, field gathering and processing infrastructure. During 2007, the Company operated more than 95 percent of its capital program. Synergies exist between all of the Company's core areas and operational and technical expertise. The Company's producing assets can be characterized as natural gas focused with medium to long-life deep basin production profiles and a low cost structure, which results in superior economic netbacks and recycle ratios.

The Company drilled 14 (8.1 net) wells in 2007 with an 80 percent success rate. This resulted in record production volumes during the fourth quarter of 2007 and proved and probable reserve additions, net of revisions, in 2007 of 3.5 million barrels of oil equivalent, replacing production by 178 percent. The 2007 net capital expenditures of $47.3 million were less than cash flow of $48.5 million.

Delphi averaged 5,868 barrels of oil equivalent per day during the fourth quarter, up 18 percent from the comparative quarter in 2006, and 5,323 boe/d for 2007, up two percent over 2006.

Finding and development costs on proved plus probable reserve additions inclusive of future development costs and revisions were $13.11 per boe, generating a recycle ratio of 2.3. Excluding prior period revisions, finding and development costs in 2007 on proved plus probable reserve additions inclusive of future development costs were $10.63 per boe. All-in finding, development and acquisition costs on the 2007 net capital program were $21.49 per boe. The capital efficiency of the 2007 development and exploration program was very strong as a result of the shift in capital spending back to the Company's

operated conventional assets with more robust economics and smaller infrastructure capital requirements.

The Company also strengthened its position to deliver long-term sustainable growth through the strategic swap of its non-operated interest in the unconventional natural gas resource play at Bigfoot for an operated high working interest position at Hythe. The Hythe assets are characterized as multi-zone, conventional, deep basin natural gas assets with significant future development and exploration potential. These are similar to the Company's Bigstone assets in North West Alberta that have been successfully developed over the past three years at less than $16.00 per boe, consistently generating a recycle ratio greater than 2.0 times. Production at Bigstone has tripled since acquiring the asset in 2005 with total capital of only 90 percent of the cash flow generated over that period.

The Hythe/Bigfoot transaction, although neutral on a production basis, was a net disposition of reserves by the Company for proceeds of $15.1 million. Therefore, offsetting the proved plus probable reserves additions from the 2007 capital program, was a net disposition of 1.6 mmboe resulting from the acquisition, swap and disposition activity during 2007.

Proved plus probable reserves at December 31, 2007 were 17.3 mmboe, equal to the comparative period in 2006, as reserve additions were partially offset by dispositions. Proved producing reserves increased 15 percent compared to 2006.

Canadian natural gas prices averaged $6.44 per mcf at AECO during 2007, down only slightly from $6.61 per mcf in 2006, but down 21 percent from $8.81 per mcf during 2005.

Delphi continued to benefit from its risk management program during 2007, realizing $8.05 per mcf from its natural gas sales, a 25 percent premium to the average AECO natural gas price in 2007. The Company's operating netback during 2007 averaged $30.76 per boe and over the past three years has averaged $30.50 per boe with a variance year-to-year of no more than $0.25 per boe. Delphi's risk management program continues to be an integral part of the Company's strategy, designed to ensure cash flow remains predictable and available to execute the planned capital programs, mitigating uncertain and volatile future natural gas prices.

Outlook

Delphi expects to spend approximately $50.0 million in 2008 - approximately 85 to 90 percent of anticipated 2008 cash flow - drilling 20 to 25 wells. The majority of the capital will be directed towards drilling and completion activities in the Bigstone, Hythe, and Noel core areas. For 2008, production is forecast to average between 6,000 boe/d to 6,200 boe/d, a 15 percent increase over 2007. First quarter production is expected to average 6,000 boe/d.

The Company has had an active winter capital program, spending approximately $24.0 million drilling 11 wells (8.2 net) with 100 percent success, as well as completing several workover, recompletion, pipeline and facility projects. Drilling is now finished with several completion and pipeline operations still ongoing. Four of the new wells are now on production and estimated on-stream dates for the remaining new wells range from mid-second quarter to mid-third quarter.

Delphi has a significant inventory of defined and repeatable conventional prospects concentrated within its core areas of operation. The multi-zone nature of Delphi's core areas and recently approved downspacing provisions contribute to the Company's large development drilling inventory. Delphi continues to pursue emerging technologies to enhance recoveries of existing reserves as well as untapped natural gas resources within the Company's current land holdings.

The Company currently trades at discount of about a 30 percent to its net asset value per share estimated to be $2.91 (discounted eight percent before tax), based on its December 31, 2007 proved plus probable reserves, as evaluated by GLJ Petroleum Consultants, which reflects only a portion of the value and growth potential of the Company.

Delphi is optimistic as to the long-term market fundamentals of natural gas. Natural gas prices have strengthened recently with prices reaching levels not seen in two years. The Company has taken advantage of this recent move in natural gas prices by increasing its hedged position to approximately 44 percent of current production for 2008 at an average price of $8.21 per mcf.

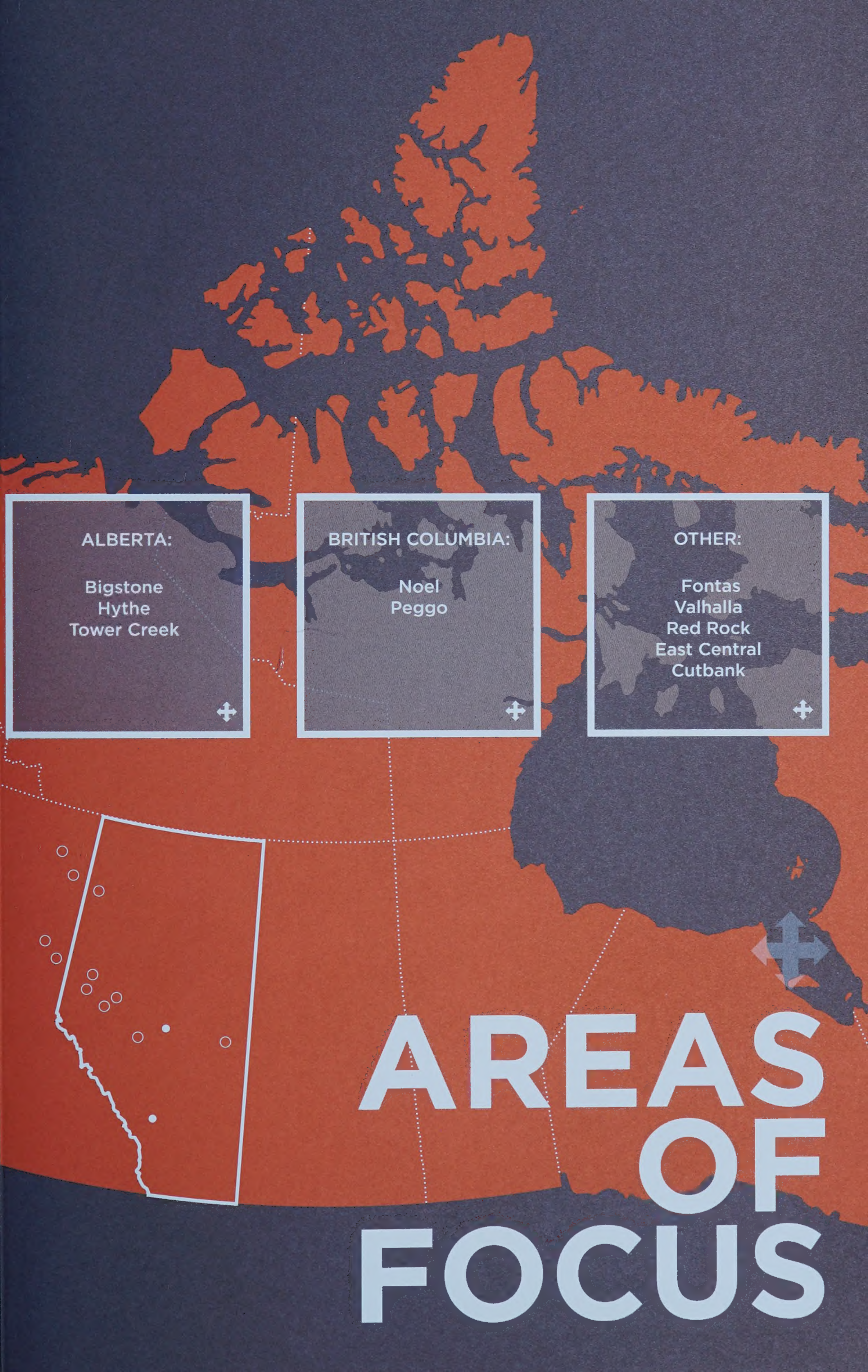
The talented and enthusiastic Delphi team has expanded by 25 percent during 2007 and is well positioned to continue to execute its proven growth strategies through 2008 and beyond.

On behalf of the Board,

David Reid

David J. Reid
President and Chief Executive Officer
March 14, 2008

AREAS OF FOCUS



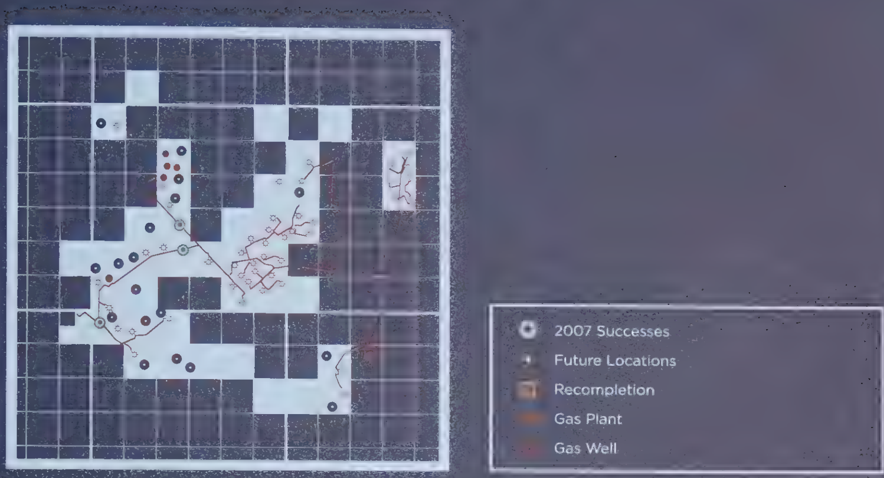
DELPHI CONTINUED TO OPTIMIZE ITS ASSETS ACHIEVING AVERAGE PRODUCTION OF 5,323 BARRELS OF OIL EQUIVALENT PER DAY IN 2007. THIS COMPARES WITH 5,228 BOE/D IN 2006 AND 4,221 BOE/D IN 2005. THE COMPANY EXITED THE YEAR PRODUCING 5,900 BOE/D WEIGHTED 80 PERCENT TO NATURAL GAS. DELPHI EXPECTS TO AVERAGE BETWEEN 6,000 AND 6,200 BOE/D IN 2008 WITH CONTINUED DEVELOPMENT SUCCESS IN THE FIELD.

OPERATIONS REVIEW

The Company's $50.0 million capital program for 2008 includes drilling 20 to 25 (15 to 18 net) wells in its core areas of North West Alberta and North East British Columbia. About 75 percent of the capital program consists of low-risk development drilling. Delphi's operations include conventional multi-zone oil and natural gas development at Bigstone and Hythe in North West Alberta; shallow natural gas development and exploration at Fontas in North West Alberta, conventional multi-zone natural gas development in North East British Columbia and lower risk oil and natural gas development opportunities in East Central Alberta. The Company expects additional upside from its exploration activities in Bigstone, Hythe and in Alberta and Noel and Cutbank in British Columbia.

ALBERTA

Delphi's assets in North West Alberta generate approximately 75 percent of the Company's current average daily production. The area offers predictable, deep basin performance, including high initial rates of sweet natural gas, moderate initial declines, and an extended period of sustainable low decline production.



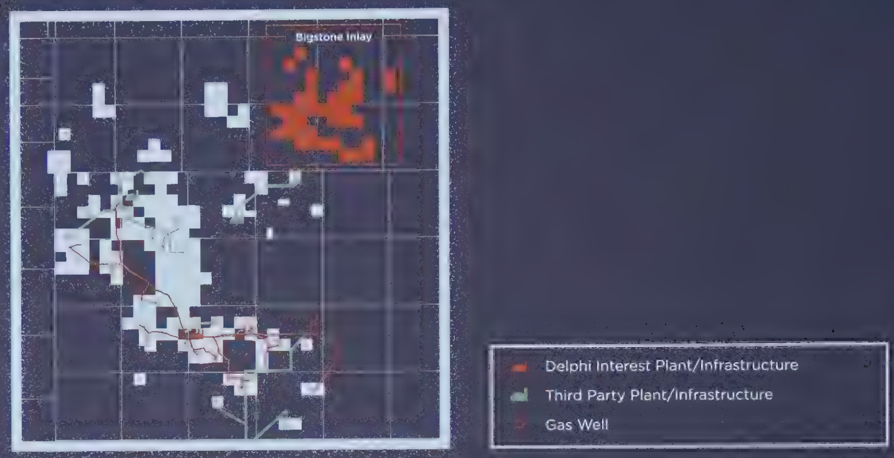
NORTH WEST ALBERTA - Bigstone

The Bigstone area which is located 150 kilometres southeast of Grand Prairie is Delphi's largest asset, producing approximately 2,800 boe/d in 2007. This represents a significant increase from the 2006 average of 2,524 boe/d and approximately 1,000 boe/d when the property was acquired in early 2005. The multi-zone nature of the property has been a major factor in achieving a 98 percent success rate on 41 wells (31 net) drilled in the area through the end of 2007. A typical producing well will come on stream at 1 to 3 mmcf/d, decline by 40 to 50 percent in the first year and then stabilize at 12 to 15 percent declines over the life of the well. The high initial production rates and premium netbacks allow Delphi to recoup its investment in less than two years and the modest decline over the remaining life of the well will generate a steady, predictable cash flow.

The majority of the prospects on the Bigstone lands have the potential to encounter up to seven productive zones, resulting in prolific multi-zone completions. The Bigstone property offers significant development upside for natural gas through step-out drilling in Cretaceous aged formations at depths of up to 2,800 metres, including the Dunvegan, Viking, and Gething. Additional development opportunities for oil exist in the Cardium interval at approximately 1,800 metres. Delphi participated in six wells (2.8 net) in Bigstone in 2007, resulting in four gas wells (2.3 net) and two oil wells (0.5 net). During the 2007/2008 winter drilling program we anticipate drilling up to six wells (4.0 net) for a gross cost of between $10.0 million and $15.0 million. One of the wells will be targeting oil in the Cardium sand which produces at rates of 100 - 150 bbls/d in offset wells and the remaining five wells will be step-outs to Cretaceous gas producers that initially produced at rates ranging from 1 to 5 mmcf/d. Delphi has identified approximately 40 locations in the area providing an inventory of drilling prospects for the next three to four years.

Recent drilling activity has resulted in several exploration discoveries in the Cretaceous Bluesky/Falher and the Triassic/Permian intervals. Multiple follow up locations to the Bluesky/Falher have been identified and will be part of the winter 2007/2008 program. Delphi is continuing to evaluate the extent, productivity and economic merits of the Triassic/Permian plays.

Delphi operates 95 percent of its production in Bigstone and owns significant infrastructure in the area including a 29 percent working interest in an 80 mmcf/d natural gas processing plant and the associated gas gathering system. The ownership in the infrastructure is instrumental in maintaining a low operating cost structure resulting in premium netbacks. Ongoing efforts to optimize the gas gathering infrastructure and processing facilities have been very successful in increasing run-times and production volumes.



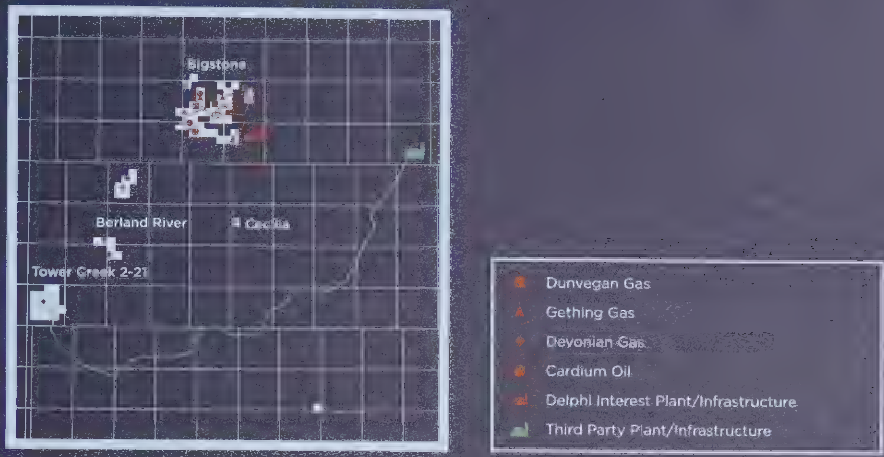
NORTH WEST ALBERTA - Hythe

In September 2007, Delphi swapped its non-operated, 50 percent working interest in the Bigfoot natural gas assets located in North East British Columbia for the operated, multi-zone natural gas assets in the Hythe area of North West Alberta. Delphi's recently acquired land base in the Hythe area is three times the size of the Company's Bigstone land base, providing a dominant footprint for expansive growth in the prolific Peace River Arch.

When Delphi acquired the Hythe assets they were producing approximately 400 boe/d of natural gas. By year end Delphi had increased production to 650 boe/d primarily through well reactivations and optimizations. As part of the transaction, Delphi received ownership in excess of 120 kilometres of gas gathering systems, a 10.9 percent ownership in a 70 mmcf/d natural gas processing plant, ownership in two field compression sites, 53,000 gross acres (39,000 net) of undeveloped land and ownership in 20 shut-in wells with significant reactivation and recompletion opportunities. In addition, Delphi received priority access to the Hythe natural gas processing plant, access to $3.0 million of seismic data and a cash payment of $15.1 million.

Swapping the prospects in Bigfoot for the proven success in Hythe increased Delphi's near-term growth prospects and financial flexibility through operatorship and control of the assets while preserving the Company's long-term growth potential. At Hythe, Delphi has focused its initial activities on well and gathering system optimization, workovers and recompletions, resulting in cost-efficient production increases. The Company anticipates additional production gains as on-going optimization projects are completed. Delphi participated in one well (0.5 net) at Hythe in the fourth quarter of 2007 and will ramp up activity significantly in 2008. The Company is licensing up to 12 locations in preparation for an expanded drilling program during the 2007/2008 winter program. Plans include recompleting or reactivating up to seven wells (4.8 net) and drilling up to five (2.6 net) low risk development wells.

Delphi has identified several productive intervals in the Hythe area that appear to be candidates for increased deliverability and reserve capture through the application of fracture stimulated horizontal wells. A study is underway to determine the best candidates for this application and several wells will be drilled this summer to evaluate the application.



Delphi's 2006 Leduc natural gas discovery at 02-21-55-27W5 was equipped, tied-in and commenced production in late June 2007. The well continues to produce at gross raw rates of 23 mmcf/d (800 boe/d net) and through the end of 2007 had cumulative production of approximately 3.3 billion cubic feet of natural gas. During July 2007, Delphi purchased an additional 10.5 percent stake in the well, well-site facilities and nearby lands for $10.5 million, increasing Delphi's working interest to 30.7 percent. As a result of the year end reserve evaluation, Delphi's reserve evaluators increased proven plus probable reserves by 29 percent based on an analysis of the production performance of the well. In addition to the revenue from the gas stream, Delphi received approximately $210,000 in 2007 (based on six months of production) from the sale of sulphur which is a by-product of processing the natural gas stream. Sales of sulphur are continuing into 2008.

Also during 2007, a well was drilled at 11-26-55-27W5 to test the seismically defined fractured Wabamun formation at a depth of 4,500 metres but was abandoned prior to reaching the proposed total depth after encountering wellbore instability in the uphole section. Delphi retains an 8.3 percent working interest in the lands covering the prospect and will consider re-drilling the prospect when the economic environment relating to the uncertainties of product pricing and deep well royalties are better defined.

BRITISH COLUMBIA

Delphi's assets' in North East British Columbia generate approximately 15 percent of the Company's current average daily production. The area offers multi-zone Cretaceous gas targets with predictable moderate declines in the south and higher deliverability Mississippian and Devonian natural gas targets in the north.

NORTH EAST BRITISH COLUMBIA - Noel

A farm-in agreement in North East British Columbia announced in June 2007 is already paying dividends. Delphi took advantage of its role as operator to drill and complete two 2,400 metre wells in the third quarter of 2007 targeting multi-zone sweet gas and light oil targets in the Falher, Cadotte, Paddy, Dunvegan and Cardium formations. The first well (0.8 net) resulted in four potentially productive intervals. Delphi restricted completion operations on the well to two intervals due to the high deliverability encountered, with the two intervals testing at a combined rate of 5,800 mcf/d. The remaining two intervals are expected to be completed at a later date. The second well (0.6 net) was completed in three different intervals with a combined test rate of 3,600 mcf/d. Production from the two wells commenced in mid-November with December production averaging 375 boe/d net to Delphi.

The success of the first two wells resulted in several additional low-risk multi-zone locations. Delphi has drilled two low-risk development wells (1.9 net) in the area over the winter drilling season targeting multi-zone sweet gas in the Falher, Cadotte, Paddy and Dunvegan formations at depths ranging from 1,400 to 2,400 metres.

Under the terms of the farm-in agreement, Delphi has now earned an interest in four productive wells (3.2 net), two of which are on production and two will be tied in during the second quarter 2008. The Company has also earned a working interest in 6,500 gross acres with an averaged working interest of 64 percent. We are continuing to evaluate opportunities on the original farm-out lands and incorporating the data from the drilling program to identify additional opportunities in the area.

NORTH EAST BRITISH COLUMBIA - Peggo

The Peggo area is a non-producing asset that has been dormant due to the lack of available take away capacity for the natural gas. Delphi has acquired a 100 percent working interest in 13 kilometres of a sour gas transmission line and a 50 percent working interest in a 30 mmcf/d natural gas processing plant. The ownership of this infrastructure will allow Delphi to re-drill a Slave Point well (0.5 net) that drill stem tested 8.0 mmcf/d, tie-in one standing Jean Marie well (0.5 net) that production tested 1.3 mmcf/d and initiate a 2008/2009 winter drilling program for an additional three licensed Jean Marie prospects.

As indicated, the primary production in the Peggo Area is from the Devonian Slave Point and Jean Marie formations. Slave Point deliverability of 5 to 10 mmcf/d has been obtained on Delphi lands through production and drill stem tests. Typical Jean Marie producers in the area achieve initial production rates of up to 4 mmcf/d and quickly decline to stabilized rates in the range of 0.5 to 1.0 mmcf/d.

OTHER

NORTH WEST ALBERTA - Fontas

Delphi has access to shallow gas development and exploration upside in Fontas, approximately 300 kilometres north of Grande Prairie. Although the number of growth opportunities in Fontas is limited, the area offers a relatively low-risk program with high netbacks. Fontas is currently producing 300 boe/d net to Delphi primarily from the relatively shallow Mississippian Debolt/Elkton and the Cretaceous Detrital formations. Delphi has a 20 percent working interest in a contiguous land base in the area of 130,000 acres, a 40 mmcf/d natural gas processing plant and associated gas gathering system.

NORTH WEST ALBERTA - Valhalla

Delphi's 2006 exploration discovery in Valhalla, Alberta, just north of Grande Prairie, was placed on stream during the second quarter of 2007. While the original discovery was in the Wabumum formation, the Company recompleted a previously drilled deep test in the shallower Mississippian zones during the second quarter. Since the well was already tied-in and equipped for production, Delphi was able to move quickly to add production of 2.0 mmcf/d (145 boe/d net).

NORTH WEST ALBERTA - Red Rock

The Red Rock area has multi-zone sweet natural gas targets including the Cadomin, Gething, Bluesky, Falher, Cadotte, Dunvegan and Cardium formations. Analog wells in Red Rock have a wide range of deliverability. A typical well has initial production of 1 to 3 mmcf/d with the more prolific wells having initial production rates in excess of 10 mmcf/d. The Red Rock activity is part of a farm-in agreement announced in June 2007. Under the agreement, Delphi has the potential to earn an interest of up to 60 percent in up to 18,000 acres of land on a rolling option basis. Delphi's partner has ownership and access to gas gathering and processing infrastructure in the immediate area.

Delphi drilled the first earning well in the Red Rock area during the summer of 2007 and finalized completion operations during January 2008. After completing four intervals a commingled test rate of 1.0 mmcf/d was achieved during a short term clean-up flow. Delphi is evaluating the results of the test information and incorporating this data into the overall development scheme prior to electing on the next earning well. Delphi has earned an 80 percent working interest in the first well and a 30 percent working interest in 3,200 gross acres.

EAST CENTRAL ALBERTA

Delphi supplements its natural gas exploration and development activities with oil-weighted production in East Central Alberta. Delphi has a large undeveloped land base in the area that offers low-risk development opportunities with all-season access. Producing intervals in the area include the Viking, Sparky, Glauconite/Cummings and Ellerslie/Dina formations. Delphi's activities are focused on completion and testing of sands in existing wellbores, infill and step-out drilling, waterflood optimization and production optimization. Total production from Delphi's assets in East Central Alberta is approximately 325 boe/d.

NORTH EAST BRITISH COLUMBIA – Cutbank

At Cutbank, the Company is in discussions with senior oil and gas producers regarding potential joint operations to develop existing acreage. Delphi has a 50 percent working interest in a previously drilled exploration well which successfully tested natural gas from two Cretaceous zones at rates in excess of 1,000 mcf/d. Several step-out locations to this discovery have been identified as part of a development program which would incorporate the tie-in of the existing discovery well.

PROVING OUR STRENGTH

OPERATIONAL STATISTICS

RESERVES

GLJ Petroleum Consultants Ltd. (GLJ), the Company's independent petroleum engineering firm, has evaluated the crude oil, natural gas and natural gas liquids reserves of the Company as at December 31, 2007 and prepared a reserves report in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities". GLJ based its evaluation on land data, well and geological information, reservoir studies, estimates of on-stream dates, contract information, operating cost data, capital budgets and future operating plans provided by the Company, information obtained from public records and GLJ's internal non-confidential files and commodity price forecast. The Audit & Reserves Committee, with the mandate of reviewing the independent engineering report, recommended the acceptance of the GLJ reserve estimates and it has been approved by the Board of Directors for the purposes of the Annual Report.

RESERVES RECONCILIATION

The reconciliation of the Company's proved, probable and proved plus probable reserves for December 31, 2007 is as follows:

RECONCILIATION OF COMPANY GROSS RESERVES [(1)]

	Crude Oil and NGL (mbbls)			Natural Gas (mmcf)			Mboe (6:1)		
	Proved	Probable	Total P+P	Proved	Probable	Total P+P	Proved	Probable	Total P+P
December 31, 2006	1,630	1,495	3,125	58,554	26,562	85,116	11,389	5,922	17,311
Discoveries and extensions	342	135	477	12,711	9,997	22,708	2,460	1,802	4,262
Technical revisions	(208)	(205)	(413)	168	(2,530)	(2,362)	(180)	(628)	(808)
Dispositions	(159)	(715)	(874)	(12,218)	(7,163)	(19,381)	(2,195)	(1,909)	(4,104)
Acquisitions	49	20	69	10,607	4,234	14,841	1,816	726	2,542
Sub-total	1,654	730	2,384	69,822	31,100	100,922	13,290	5,913	19,203
Production	(308)	–	(308)	(9,814)	–	(9,814)	(1,943)	–	(1,943)
December 31, 2007	1,346	730	2,076	60,008	31,100	91,108	11,347	5,913	17,260

(1) Gross reserves represent the Company's interest before deducting royalties and including any royalty interest of the Company.

SUMMARY OF RESERVES

The following table outlines the oil and natural gas liquids and natural gas reserves of the Company by product type on a Company interest (before royalties) basis. Proved and Proved plus Probable Reserves were essentially unchanged from the previous year. The Bigfoot/Hythe asset swap, which included a cash consideration paid to the Company, resulted in a net reserves disposition for the Company. The Bigfoot reserve report for 2006 was characterized as 53 percent of the reserves being non-producing, including undeveloped. Due to the resource nature of the asset, undeveloped reserves are readily supported and were booked under NI 51-101 guidelines. The Hythe asset is more conventional and is characterized as only 40 percent of the reserves being non-producing. Although the reserves in Hythe have a higher discounted value on a per boe basis, the transaction resulted in a net disposition of reserves. The Company also entered into a transaction that saw the disposition of non-producing probable reserves at John Lake.

Company gross reserves [1]	2007	2006	% change
Proved producing oil & NGLs (mbbls)	**1,079**	1,294	(17)
Proved producing natural gas (mmcf)	**47,845**	39,401	21
Total proved producing (mboe)	**9,053**	7,861	15
Proved oil & NGLs (mbbls)	**1,346**	1,630	(17)
Proved natural gas (mmcf)	**60,008**	58,554	2
Total proved (mboe)	**11,347**	11,389	–
Probable oil & NGLs (mbbls)	**730**	1,495	(51)
Probable natural gas (mmcf)	**31,100**	26,562	17
Total probable (mboe)	**5,913**	5,922	–
Proved plus probable oil & NGLs (mbbls)	**2,076**	3,125	(34)
Proved plus probable natural gas (mmcf)	**91,108**	85,116	7
Total proved plus probable (mboe)	**17,260**	17,311	–

(1) Gross reserves represent the Company's interest before deducting royalties and including any royalty interest of the Company.

ESCALATED PRICING ASSUMPTIONS

The following table sets forth GLJ's escalated commodity price, currency exchange rate and inflation rate forecasts used in the preparation of the reserve estimates of the Company.

Pricing assumptions	West Texas Intermediate	Edmonton Light	AECO Spot	Exchange Rate	Inflation
	(US$/bbl)	(CDN$/bbl)	(CDN$/mmbtu)	(US$/CDN$)	(%)
2008	92.00	91.10	6.75	1.0	2.0
2009	88.00	87.10	7.55	1.0	2.0
2010	84.00	83.10	7.60	1.0	2.0
2011	82.00	81.10	7.60	1.0	2.0
2012	82.00	81.10	7.60	1.0	2.0
2013	82.00	81.10	7.60	1.0	2.0
2014	82.00	81.10	7.80	1.0	2.0
2015	82.00	81.10	7.97	1.0	2.0
2016	82.02	81.12	8.14	1.0	2.0
2017	83.66	82.76	8.31	1.0	2.0
Thereafter [1]					

(1) Percentage change of 2.0% represents the change in future prices each year after 2017 to the end of the reserve life.

NET PRESENT VALUE OF RESERVES - ESCALATED PRICING [1] [2]

The net present values of future net revenue of the Company's reserves at various discount rates on a before income tax basis are outlined below.

($ thousands)	Undiscounted	Discounted at 8%	Discounted as 10%
Proved			
Developed producing	227,600	170,084	160,464
Developed non-producing	34,108	23,797	22,018
Undeveloped	15,902	10,074	9,099
Total proved	**277,610**	**203,955**	**191,581**
Probable	149,890	83,551	74,265
Total proved plus probable	**427,500**	**287,506**	**265,846**

(1) Before income taxes.
(2) As required by NI 51-101, undiscounted well abandonment costs of $5.6 million for total proved and $6.9 million for total proved plus probable; 8% discounted well abandonment costs of $3.2 million for total proved and $3.3 million for total proved plus probable; 10% discounted well abandonment costs of $2.9 million for total proved and $2.9 million for total proved plus probable are included in the net present value determinations.

FINDING AND DEVELOPMENT COSTS

The Company has presented its finding and development costs in accordance with NI 51-101. The Company has also calculated finding and development costs including acquisitions and dispositions. Finding and development costs were substantially improved in 2007 as the Company focused its capital program on its conventional assets in the Peace River Arch and Deep Basin. Proved plus Probable finding, development and acquisition costs were essentially the same as Proved costs due to the net disposition of Probable reserves associated with the Bigfoot/Hythe swap and disposition of John Lake for which the Company received $15.5 million in cash. The Company believes that as Hythe is evaluated and exploited Probable reserves will be added at a finding and development cost better than the price received on these dispositions. An additional 10.5 percent working interest was acquired at the Tower Creek 2-21-55-27W5 well (Company interest 30.7 percent) at $18.48/boe and $15.20/boe for Total Proved and Total Proved plus Probable reserves respectively.

($ thousands)	**2007**	2006	2005-2007
Capital invested			
Land and seismic	**611**	13,648	14,604
Drilling and completion	**38,417**	86,473	162,077
Other	**2,261**	1,906	5,531
Facilities	**10,635**	62,137	95,071
	51,924	164,164	277,283
Change in future development costs			
Proved reserves	**(5,971)**	12,085	8,024
	45,953	176,249	285,307
Probable reserves	**(670)**	11,147	9,229
Total on-stream costs	**45,283**	187,396	294,536
Acquisitions	**10,871**	1,188	63,332
Dispositions	**(15,502)**	(34,918)	(56,282)
Total capital invested	**40,652**	153,666	301,586
Reserve discoveries, extensions and revisions			
Proved (mboe)	**2,280**	3,527	8,786
Proved plus probable reserves (mboe)	**3,453**	5,812	12,480
Reserve net additions (1)			
Proved (mboe)	**1,901**	2,878	9,979
Proved plus probable reserves (mboe)	**1,891**	4,796	12,693
Finding and development costs ($/boe) (2)			
On-stream costs excluding future development costs			
Proved	**22.77**	46.54	31.56
Proved plus probable reserves	**15.03**	28.25	22.22
On-stream costs including future development costs			
Proved	**20.15**	49.97	32.47
Proved plus probable reserves	**13.11**	32.24	23.60
Total capital invested			
Proved	**21.74**	49.52	29.30
Proved plus probable reserves	**21.49**	32.04	23.76

(1) Includes discoveries, extensions, revisions, acquisitions and dispositions.
(2) The aggregate of the exploration and development costs incurred in the most recent financial year, included in capital invested, and the change in estimated future development costs, generally will not reflect total finding and development costs related to reserve additions for that year.

RESERVE LIFE INDEX

The reserve life index of Delphi has been calculated by using average 2007 production of 5,323 boe/d. The reserve life index is 8.9 years on a proved plus probable basis.

	Crude Oil and NGL (mbbls)			**Natural Gas** (mmcf)			**Mboe** (6:1)		
	Proved	Probable	Total	Proved	Probable	Total	Proved	Probable	Total
Reserves - Dec. 31, 2007	1,346	730	2,076	60,008	31,100	91,108	11,347	5,913	17,260
Production	308		308	9,814		9,814	1,943		1,943
Reserves life index (years)	**4.4**		**6.7**	**6.1**		**9.3**	**5.8**		**8.9**

RESERVES PER OUTSTANDING COMMON SHARE

The proved plus probable reserves per 1,000 common shares of the Company was 254 compared to 285 in the previous year, a decrease of eleven percent.

	2007	2006	%Change
Proved and probable reserves (mboe)	**17,260**	17,311	–
Proved and probable boe reserves per 1,000 outstanding common share	**254**	285	(11)

ACREAGE SUMMARY

The Company's total and undeveloped landholdings as at December 31, 2007 are outlined below.

December 31, 2007	Total		Undeveloped		Fair Market
(acres and $ thousands)	Gross	Net	Gross	Net	Value (1)
Alberta	344,895	121,190	185,680	71,444	8,573
British Columbia	136,570	37,777	66,283	18,282	1,806
Total	**481,465**	**158,967**	**251,963**	**89,726**	**10,379**

(1) Undeveloped land value of $10.4 million at December 31, 2007 for undeveloped land based on Seaton-Jordan & Associates Ltd. land valuation report.

RECYCLE RATIO

The recycle ratio is a measure of the effectiveness of the Company's re-investment program. The recycle ratio is a key indicator in the oil and gas industry of efficiency and profitability and is calculated by dividing the finding and development costs for total capital invested into the Company's operating netback.

Year ended December 31	**2007**	2006
Operating netback ($/boe)	**30.76**	30.49
Proved plus probable reserves F, D&A costs ($/boe)	**21.49**	32.04
Proved plus probable recycle ratio	**1.43**	0.95

NET ASSET VALUE

The net asset values of the Company for December 31, 2007 at a discount rate of eight and ten percent before taxes are summarized below.

($ thousands except per share value)	8%	10%
Estimated net future revenues of proved plus probable reserves discounted	287,506	265,846
Undeveloped land (1)	10,379	10,379
Mark-to-market value of hedging contracts	4,074	4,074
In-the-money option proceeds (2)	3,769	3,769
Total assets value	305,718	284,068
Bank debt plus working capital deficiency	(100,658)	(100,658)
Net asset value	205,060	183,410
Common shares outstanding and in-the-money options	70,550,491	70,550,491
Net asset value per share	**2.91**	**2.60**

(1) Undeveloped land and seismic includes value of $10.4 million at December 31, 2007 for undeveloped land based on Seaton-Jordan & Associates Ltd. land valuation report.
(2) In-the-money option proceeds are based on the closing December 31, 2007 share price of $1.83.
(3) The Company estimates it has approximately $182 million of tax deductions available to offset future taxable income.

MANAGEMENT DISCUSSION AND ANALYSIS

(all tabular amounts are expressed in thousands of dollars, except per unit amounts)

THE MANAGEMENT DISCUSSION AND ANALYSIS HAS BEEN PREPARED BY MANAGEMENT AND REVIEWED AND APPROVED BY THE BOARD OF DIRECTORS OF DELPHI ENERGY CORP. ("DELPHI" OR "THE COMPANY"). THE DISCUSSION AND ANALYSIS IS A REVIEW OF THE FINANCIAL RESULTS OF THE COMPANY BASED UPON ACCOUNTING PRINCIPLES GENERALLY ACCEPTED IN CANADA. ITS FOCUS IS PRIMARILY A COMPARISON OF THE FINANCIAL PERFORMANCE FOR THE THREE AND TWELVE MONTHS ENDED DECEMBER 31, 2007 AND 2006 AND SHOULD BE READ IN CONJUNCTION WITH THE AUDITED FINANCIAL STATEMENTS AND ACCOMPANYING NOTES FOR THE YEAR ENDED DECEMBER 31, 2007 AND 2006. THE DISCUSSION AND ANALYSIS HAS BEEN PREPARED AS OF MARCH 18, 2008.

OPERATIONAL AND FINANCIAL HIGHLIGHTS

Delphi Energy Corp. achieved strong production growth in 2007 with average daily production increasing on a quarter over quarter basis throughout the year from an average of 4,322 barrels of oil equivalent per day (boe/d) in the first quarter to 5,868 boe/d in the fourth quarter, an increase of 36 percent over the year. Fourth quarter sales volumes represent record quarterly production for the Company. Average annual production volumes increased to 5,323 boe/d, an increase of two percent compared to 2006. Natural gas production comprised 84 percent of the Company's average production.

Several accomplishments were achieved in 2007 through the Company's capital program including:

- the continued growth in production of its core area of Bigstone, Alberta to over 3,000 boe/d at the end of 2007 from 2,300 boe/d in December, 2006;
- the swap of the Company's 50 percent working interest, Jean Marie resource play at Bigfoot, British Columbia in exchange for 84 sections of primarily operated, multi-zone, conventional natural gas on average 74 percent working interest lands with infrastructure and production at Hythe, Alberta and cash of $15.1 million;

- production growth at Hythe, Alberta to 650 boe/d from 400 boe/d at the time of acquisition in September, 2007;

- the production start-up and the acquisition of an additional 10.5 percent working interest in the long-life natural gas production at Tower Creek, Alberta; and

- the expansion of opportunities in the deep gas basin with the addition of drill ready farm-in opportunities at Noel, British Columbia and Red Rock, Alberta.

Funds from operations in 2007 were $48.5 million or $0.72 per basic share, compared to $49.6 million or $0.85 per basic share in 2006, maintaining strong cash netbacks in a challenging natural gas price environment. Delphi's risk management program continued to significantly contribute to funds from operations providing the Company with the ability to execute on its capital program. Gains on physical and financial hedges were $10.8 million representing 22 percent of funds from operations and $5.54 per barrel of oil equivalent (boe) on a cash netback basis.

The Company's financial position strengthened significantly in 2007 providing greater financial flexibility going into 2008 to execute its capital program and participate in farm-in, joint venture or acquisition opportunities. At December 31, 2007 the Company had net debt of $100.7 million down from $118.2 million at December 31, 2006. On an annualized fourth quarter funds from operations basis, Delphi improved its debt to cash flow ratio to 1.8 times from 2.5 times at the end of 2006.

BUSINESS ENVIRONMENT

Benchmark Prices

	Three Months Ended December 31			Twelve Months Ended December 31		
	2007	2006	% Change	**2007**	2006	% Change
Natural gas						
NYMEX (US $/mmbtu)	**6.97**	6.65	5	**6.97**	6.75	3
AECO (CDN $/mcf)	**6.15**	6.90	(11)	**6.44**	6.61	(3)
Crude oil						
West Texas Intermediate (US $/bbl)	**90.68**	59.95	51	**72.31**	66.22	9
Edmonton Light (CDN $/bbl)	**86.42**	65.45	32	**76.35**	72.77	5
Foreign exchange rate						
Canadian to US dollar	**0.98**	1.14	(14)	**1.08**	1.14	(5)
US to Canadian dollar	**1.02**	0.88	16	**0.93**	0.88	6

Natural Gas

United States natural gas prices are commonly referenced to the New York Mercantile Exchange Henry Hub in Louisiana (NYMEX) while Canadian natural gas prices are typically referenced to the Canadian Alberta Energy Company interconnect with the TransCanada Alberta system (AECO). Natural gas prices are influenced more by North American supply and demand than global fundamentals, however, with the growth in natural gas liquefaction and regasification facilities around the world this North American supply and demand balance has become subject to disruption. The increase in capacity of natural gas liquefaction and regasification facilities has resulted in natural gas in North America becoming a more global commodity with influences from world weather conditions and global supply in the form of liquefied natural gas (LNG) delivered to the United States.

In 2007, it was again a challenging year for natural gas prices. While United States natural gas storage levels were reduced significantly from strong late-winter withdrawals, LNG imports

to the U.S. were significantly higher than average throughout the spring and summer, due to strong U.S. pricing relative to global market prices, more than offsetting lower Canadian supply levels. By early August natural gas storage levels surpassed the record levels of 2006 resulting in a sharp decrease in the price of natural gas. Since reaching the high in August, the injections from LNG imports have been below average levels. Canadian natural gas prices were also negatively affected by the surge in the Canadian dollar relative to the United States dollar. During the year, the AECO average daily spot price ranged from a high of $8.27 per mcf to a low of $4.33 per mcf. For internal forecasting purposes, looking toward 2008, Delphi anticipates AECO natural gas prices will average approximately $7.00 per thousand cubic feet (mcf).

Crude Oil

West Texas Intermediate at Cushing, Oklahoma (WTI) is the benchmark reference for North American crude oil prices. Canadian crude oil prices are based upon postings, primarily at Edmonton, Alberta and represent the WTI price adjusted for quality and transportation differentials as well as the US/CDN dollar exchange rate.

In contrast to natural gas prices, 2007 was another excellent year for crude oil prices which continued to increase, reaching over U.S. $110.00 per barrel early in 2008, on continued strong global demand, production disruptions, never ending geopolitical unrest in major producing regions and the recent devaluation of the U.S. dollar. The outlook for oil remains bullish despite concerns of a U.S. recession resulting from the sub-prime mortgage and related asset backed commercial paper fallout. For Canadian producers the significant gain in oil prices throughout the year was partially offset by a strong increase in the Canadian dollar which moved to parity for the first time since the mid – 70's. The Canadian dollar continues to remain around parity with the U.S. dollar. For internal forecasing purposes, Delphi anticipates WTI to average between U.S. $80.00 to $90.00 per barrel and the Canadian dollar to remain at, or near, par with the U.S. dollar throughout 2008.

Prices for heavy oil and other lesser quality crude oils trade at a discount or differential to light crude oil due to the additional costs in the refining process. The average differential in 2007 was $22.83 per barrel compared to $21.23 per barrel in 2006. The differential varied from a low of $13.68 per barrel to a high of $41.01 per barrel. The increase in the average differential and stronger Canadian dollar was more than offset by higher light oil prices resulting in Bow River crude prices increasing to $53.52 per barrel from $51.54 per barrel in 2006.

Industry Cost of Services

Early in 2007, the oilfield services sector was under pressure with strong demand for equipment through the winter drilling season while facing labour shortages to operate the equipment, a continuation of the rapid pace and hyper-inflation of 2006, leaving no time to maintain or service the equipment. Commodity prices, both crude oil and natural gas, remained robust and increasing through the early part of the year. Oil and gas producers incurred high day rates for drilling, completion and pipeline operations often working with crews that had less experience than was desirable. While crude oil prices continued to increase throughout the remainder of the year, natural gas prices decreased to an average low in the third quarter not seen since 2002. In addition, the Government of Alberta proposed changes to its royalty regime in September 2007 to become effective January 1, 2009.

The proposed royalty changes and low natural gas prices caused the capital markets to pull back from investing in most junior oil and natural gas producers. Oil and natural gas producers reduced capital programs due to lower funds from operations and were faced with the inability to raise equity in the capital markets. Oilfield service companies followed by reducing their rates to keep as many crews busy as possible. Through the latter half

of the year well stimulations were being completed for 40 to 50 percent less than peak rates and average drilling day rates decreased 15 to 20 percent. For oil and gas producers lower costs have continued through the 2007/2008 winter drilling season with a significant improvement in the skill level of the oilfield crews and fewer equipment breakdowns due to maintenance of the equipment through the summer and fall of 2007.

FINANCIAL STRATEGY

The Company maintains an active risk management program as an integral part of its overall financial strategy to mitigate volatility in funds from operations resulting from fluctuating commodity prices. The strategy takes advantage of the upward swings in natural gas prices as a result of the changes in demand/supply fundamentals and/or the movement of significant financial assets invested in the natural gas market as a pure commodity play. Delphi's risk management program continues to consist of both fixed price contracts and costless collars, which provide downside protection and the opportunity to share in the upside if market prices increase above the floor price. Currently, Delphi has hedged approximately 44 percent of its before-royalty natural gas production at a predominantly AECO based average floor price of $8.21 per mcf for 2008. Delphi has a strategy of hedging between 40 to 50 percent of its natural gas production as long as demand/supply fundamentals indicate volatile markets in the future. As the Company's leverage improves and/or demand/supply fundamentals move toward equilibrium or reduced supply, Delphi will manage its hedging program accordingly to take advantage of exposure to higher natural gas commodity prices.

Delphi continues to direct efforts at maintaining or reducing its controllable costs. Increasing production at its various operating fields through Company owned infrastructure reduces fixed costs on a per boe basis and improves netbacks. Field operators are encouraged to undertake preventative maintenance on field infrastructure and wellsite equipment to minimize production downtime and prevent significant operating costs associated with repairs. In a cost environment which continues to be affected by quality labour shortages and increasing costs of supplies, the Company strives to achieve improvement in its costs of production and at a minimum maintain current production costs.

Maintaining or improving strong operating netbacks per boe through the risk management program and the control of costs associated with production operations, allows the Company to pursue its planned capital program with greater confidence that financial flexibility will be maintained while incurring capital expenditures to grow production volumes. With the expectation of a pricing environment very similar to the past two years, the Company expects to maintain an operating netback per boe in the $29.00 - $31.00 range as it has in the past three years despite the swings in AECO spot pricing. The risk management program has been and will continue to be an integral part of ensuring strong netbacks.

The capital expenditure program will continue to be slightly less than forecast funds from operations. Additional capital may be approved as a result of incremental cash from greater than expected production growth, higher than forecast cash netbacks or other sources of financing.

Delphi continues to be focused on reducing its leverage and improving its financial flexibility through net debt reduction or increasing funds flow growth resulting in a lower net debt to annualized quarterly funds from operations ratio. The Company is focused on achieving its internal target range for this ratio of 1.3 to 1.5 times.

SELECTED INFORMATION

The following table sets forth certain information of the Company for the past eight consecutive quarters.

	Dec. 31 2007	Sept.30 2007	Jun. 30 2007	Mar. 31 2007	Dec. 31 2006	Sept. 30 2006	Jun. 30 2006	Mar. 31 2006
Production								
Natural gas (mcf/d)	**30,610**	**28,196**	**26,967**	**21,658**	24,919	25,403	28,797	23,695
Oil (bbl/d)	**346**	**579**	**423**	**366**	388	444	531	544
Natural gas liquids (bbl/d)	**420**	**422**	**461**	**346**	441	412	503	518
Barrels of oil equivalent (boe/d)	**5,868**	**5,700**	**5,379**	**4,322**	4,982	5,090	5,834	5,011
Financial								
($ thousands except per unit amounts)								
Petroleum and natural gas revenue	**26,632**	**24,548**	**24,779**	**21,974**	22,928	21,587	25,865	23,809
Funds from operations	**13,747**	**12,600**	**11,469**	**10,665**	11,817	10,902	14,452	12,380
Per share - basic	**0.20**	**0.19**	**0.17**	**0.17**	0.19	0.18	0.26	0.22
Per share - diluted	**0.20**	**0.18**	**0.17**	**0.17**	0.19	0.18	0.26	0.22
Net earnings (loss)	**1,732**	**(1,348)**	**797**	**(11,653)**	290	658	4,768	1,187
Per share - Basic	**0.03**	**(0.02)**	**0.01**	**(0.18)**	–	0.01	0.09	0.02
Per share - Diluted	**0.03**	**(0.02)**	**0.01**	**(0.18)**	–	0.01	0.09	0.02

Production for the last eight consecutive quarters reflects the following events: The increase in production volumes for the second quarter of 2006 were from Bigfoot in North East British Columbia as wells were placed on stream followed by a reduced capital program leading to production declines and the disposition of several minor, non-operated properties in the latter half of 2006. In 2007 success at Bigstone, Alberta throughout the year and Noel, British Columbia in the third quarter complemented the mid-year start up of production at Tower Creek, Alberta resulting in consistent quarter over quarter production growth. Revenue and funds from operations reflected the cycle of natural gas prices and production volumes. Natural gas prices over the past two years have reflected the cyclical nature of demand. Higher prices in the winter months reflecting demand for heating weaken through the summer months as production is placed in storage for the upcoming heating season demand. In the first quarter of 2007, net earnings were significantly reduced by the impairment of goodwill in the amount of $12.1 million.

	2007	2006	2005
Revenue	**97,933**	94,189	80,880
Net earnings/(loss)	**(10,472)**	6,903	6,677
Total assets	**311,735**	326,668	244,666
Bank debt plus working capital	**100,658**	118,178	61,020

The increase in revenue from 2005 to 2006 is due to production increasing from 4,221 boe/d to 5,228 boe/d. The change in net earnings(loss) was primarily due to the impairment of goodwill recorded in March 2007. The increase in total assets and bank debt plus working capital from 2005 to 2006 relates to the significant capital program undertaken in 2006 associated with the Bigfoot joint venture. Net earnings(loss) per basic and diluted share were ($0.16), $0.12 and $0.13 respectively for the past three years.

DRILLING RESULTS

	Three Months Ended December 31		Twelve Months Ended December 31	
	Gross	Net	Gross	Net
Natural gas wells	**1.0**	**1.0**	**9.0**	**6.0**
Oil wells	**–**	**–**	**2.0**	**0.5**
Dry holes	**2.0**	**1.2**	**3.0**	**1.6**
Total wells	**3.0**	**2.2**	**14.0**	**8.1**
Success rate (%)	**33**	**45**	**79**	**80**

The Company had another successful year with the drill bit resulting in a drilling success rate of 80 percent. The Company has in excess of one hundred drilling locations identified within its core areas of operations.

CAPITAL INVESTED

	Three Months Ended December 31			Twelve Months Ended December 31		
	2007	2006	% Change	**2007**	2006	% Change
Land	**(26)**	535	–	**204**	3,578	(94)
Seismic	**(30)**	–	–	**407**	10,070	(96)
Drilling and completions	**13,188**	3,544	272	**38,417**	86,473	(56)
Equipping and facilities	**3,693**	7,646	(52)	**10,635**	62,137	(83)
Property acquisition	**–**	–	–	**10,871**	1,188	815
Capitalized expenses	**578**	368	57	**2,261**	1,825	24
Other	**(412)**	31	–	**–**	81	–
Capital invested	**16,991**	12,124	40	**62,795**	165,352	(62)
Proceeds on disposition	**–**	(17,867)	–	**(15,502)**	(34,918)	(56)
Net capital	**16,991**	(5,743)	–	**47,293**	130,434	(64)

Delphi had a very successful capital program in a challenging environment. With a net capital program less than funds from operations, Delphi achieved significant growth in production, strong capital efficiency metrics and an improvement in its financial position.

In 2007, Delphi's net capital expenditure program was $47.3 million, a significant reduction from the capital incurred compared to the prior year due to the $91.4 million capital requirement in the Bigfoot area of North East British Columbia in 2006. The majority (61 percent) of 2007 capital expenditures before dispositions, were directed at increasing production and reserves through drilling operations and optimization projects in core areas. The Company also acquired an additional 10.5 percent working interest in the Tower Creek 2-21 Leduc exploration discovery and completed the construction and commissioning of the associated pipeline and facilities, with production commencing mid year. During the year, Delphi undertook the strategic swap of its 50 percent working interest, resource play at

Bigfoot, British Columbia in exchange for 84 sections of operated, multi-zone, conventional natural gas at Hythe, Alberta and cash of $15.1 million. Highlights of the swap transaction, at the time of acquisition, were as follows:

	Hythe, Alberta	Bigfoot, British Columbia
Land	39,000 net acres	35,229 net acres
Processing plant	10.9 percent ownership in 70 mmcf/d plant	No plant interest
Gathering system	120 kilometres of gathering system	50 kilometres of gathering system
Production	400 boe/d	400 boe/d
Formations	Multizone Cretaceous	Jean Marie
Access	Year round	Primarily winter
Operator	Delphi Energy Corp.	Joint Venture Partner

PRODUCTION

	Three Months Ended December 31			Twelve Months Ended December 31		
	2007	2006	% Change	**2007**	2006	% Change
Natural gas (mcf/d)	**30,610**	24,919	23	**26,886**	25,706	5
Crude oil (bbl/d)	**346**	388	(11)	**429**	476	(10)
Natural gas liquids (bbl/d)	**420**	441	(5)	**413**	468	(12)
Total (boe/d)	**5,868**	4,982	18	**5,323**	5,228	2

Production for the twelve months ended December 31, 2007 averaged 5,323 boe/d, an increase of two percent over the comparative period primarily due to the start up of production at Tower Creek and the successful drilling program at Bigstone, Alberta offsetting lower than average annual production in the first quarter of the year. With the disposition of 250 boe/d and minimal capital directed at drilling in late 2006, production for the first quarter of 2007 averaged 4,322 boe/d. From the first quarter average Delphi managed to grow quarter over quarter production primarily through the drill bit exiting the year at 5,900 boe/d. Fourth quarter production average was a 36 percent increase over the first quarter average, proving the strength of the Company's core assets and ability to grow organically. The success was achieved in adding production at less than $25,000 per flowing boe in its core areas. Delphi believes it can continue to add production at these attractive metrics. The Company's production portfolio for the year was weighted 84 percent to natural gas, eight percent to crude oil and eight percent to natural gas liquids. Production for the three months ended December 31, 2007 increased 18 percent over the prior year's comparative period. The significant growth is attributed to drilling and optimization success in the core areas of Bigstone and Hythe, Alberta and Noel, British Columbia and the start up of production at Tower Creek.

Natural gas volumes increased to 30.6 mmcf/d in the fourth quarter of 2007, representing a 23 percent increase over the comparative period in 2006. Annual production of natural gas in 2007 was 5 percent greater than the prior year.

Crude oil production was 11 percent and 10 percent lower respectively, for the three and twelve months ended December 31, 2007, as compared to the comparative periods in 2006 due to natural declines and minimal capital investment towards adding new production.

Natural gas liquids were 5 percent and 12 percent lower respectively, for the three and twelve months ended December 31, 2007, as compared to the comparative periods in 2006 due to leaner natural gas streams on targeted zones in Bigstone.

REALIZED SALES PRICES

	Three Months Ended December 31			Twelve Months Ended December 31		
	2007	2006	% Change	**2007**	2006	% Change
AECO ($/mcf)	**6.15**	6.90	(11)	**6.44**	6.61	(3)
Heating content and marketing ($/mcf)	**0.40**	0.39	3	**0.51**	0.32	59
Gain on physical contracts ($/mcf)	**0.80**	1.12	(29)	**0.95**	1.12	(15)
Gain/(loss) on financial contracts ($/mcf)	**0.26**	–	–	**0.15**	(0.02)	–
Realized gas price ($/mcf)	**7.61**	8.41	(10)	**8.05**	8.03	–
Realized oil price ($/bbl)	**71.10**	47.09	51	**61.28**	53.19	15
Realized natural gas liquids price ($/bbl)	**76.03**	48.55	57	**62.28**	56.25	11
Total realized sales price ($/boe)	**49.33**	50.02	(1)	**50.41**	49.36	2

For the three and twelve months ended December 31, 2007, Delphi continued to benefit from its risk management program in which the Company fixed the price on a portion of its natural gas production at amounts significantly higher than the AECO spot price. For the quarter, the risk management program increased the average price received by approximately $1.06 per mcf with physical contracts adding $0.80 per mcf and financial contracts adding $0.26 per mcf. For the year ended December 31, 2007, the average realized gas price was virtually unchanged from the comparable year. The inelasticity of the average price received is directly related to Delphi's effective risk management program. In addition, the Company continues to receive higher than the AECO spot price on natural gas sales due to the high heating content of its natural gas production and the sale of approximately 3,500 million british thermal units (mmbtu) per day on the Alliance pipeline which is priced at the Chicago Monthly Index. The risk management program increased the average price received for the twelve months ended December 31, 2007 by $1.10 per mcf.

The following table outlines the premium Delphi realized on natural gas compared to the average quarterly AECO price due to the effective risk management program, quality of production and gas marketing arrangements.

	Dec. 31 2007	**Sept. 30 2007**	**Jun. 30 2007**	**Mar. 31 2007**	Dec. 31 2006	Sept. 30 2006	Jun. 30 2006	Mar. 31 2006
Natural Gas Price ($/mcf)								
Delphi realized	**7.61**	**7.20**	**8.20**	**9.61**	8.41	7.20	7.59	8.54
AECO average	**6.15**	**5.14**	**7.06**	**7.40**	6.90	6.04	6.00	7.51
Premium to AECO	**24%**	**40%**	**16%**	**30%**	22%	19%	27%	14%

Delphi's oil production is predominantly medium grade oil; therefore the Company's average price fluctuates with the quality differential. Increased production of light oil at Bigstone continues to high grade the Company's quality of crude oil resulting in pricing more reflective of light oil. Realized natural gas liquids prices have increased due to the

increase in price received for condensate, the primary component of the Company's natural gas liquid production.

RISK MANAGEMENT ACTIVITIES

Delphi enters into both financial and physical commodity contracts as part of its risk management program to manage commodity price fluctuations to ensure sufficient cash is generated to fund its capital program particularly when commodity prices are extremely volatile. Delphi makes a concerted effort to hedge production volumes at prices greater than the upper limit of the historical three to five year AECO price range of $5.25 to $8.40 per mcf and is quick to react to price aberrations such as those experienced at the end of 2005. Another component of the risk management program is to layer fixed price contracts in over a period of time, as opposed to locking in a significant portion of volumes at any one point in time, to take advantage of unexpected price spikes. For natural gas production, Delphi has hedged approximately 44 percent of its before-royalty natural gas production at a predominately AECO based average floor price of $8.21 per mcf for 2008.

With respect to financial contracts, which are derivitive financial instruments, management has elected not to use hedge accounting and consequently records the fair value of its natural gas financial contracts at each reporting period with the change in the fair value being classified as unrealized gains and losses in the statement of earnings.

The Company recognized an unrealized non-cash gain on risk management activities for the year ended December 31, 2007 of $0.8 million and an unrealized non-cash loss of $0.9 million on financial contracts in the fourth quarter of 2007. The fair values of these contracts are based on an approximation of the amounts that would have been paid to or received from counterparties to settle the contracts outstanding at the end of the period with reference to forward prices and market values provided by independent sources. Due to the inherent volatility in commodity prices, actual amounts realized may differ from these estimates.

The Company has fixed the price applicable to future production through the following contracts:

Time Period	Commodity	Type of Contract	Quantity Contracted	Contract Price ($/unit)
November 2007 - March 2008	Natural Gas	Physical	3,000 GJ/d	$9.00 floor/$9.98 ceiling
November 2007 - March 2008	Natural Gas	Physical	2,000 mmbtu/d	U.S. $10.28 fixed
November 2007 - March 2008	Natural Gas	Physical	2,000 GJ/d	$7.75 floor/$9.03 ceiling
November 2007 - March 2008	Natural Gas	Physical	2,000 GJ/d	$8.00 floor/$10.02 ceiling
November 2007 - March 2008	Natural Gas	Financial	1,500 GJ/d	$8.55 fixed
November 2007 - March 2008	Natural Gas	Physical	1,500 GJ/d	$8.55 fixed
April 2008 - October 2008	Natural Gas	Physical	4,000 GJ/d	$7.21 fixed
April 2008 - October 2008	Natural Gas	Physical	3,000 GJ/d	$7.61 fixed
April 2008 - October 2008	Natural Gas	Physical	2,000 mmbtu/d	U.S. $8.00 fixed
April 2008 - October 2008	Natural Gas	Financial	1,000 GJ/d	$8.07 fixed
April 2008 - October 2008	Natural Gas	Financial	1,000 GJ/d	$8.07 fixed
April 2008 - October 2008	Natural Gas	Financial	1,000 GJ/d	$7.75 floor/$9.55 ceiling
April 2008 - December 2008	Natural Gas	Physical	2,000 GJ/d	$7.82 fixed
April 2008 - March 2009	Natural Gas	Physical	2,000 GJ/d	$7.30 fixed
November 2008 - March 2009	Natural Gas	Physical	4,000 GJ/d	$7.46 fixed
November 2008 - March 2009	Natural Gas	Physical	2,000 GJ/d	$7.62 fixed
November 2008 - March 2009	Natural Gas	Physical	2,000 GJ/d	$7.00 floor/$8.05 ceiling
November 2008 - March 2009	Natural Gas	Physical	2,000 mmbtu/d	U.S. $9.00 fixed
November 2008 - March 2009	Natural Gas	Financial	1,000 GJ/d	$8.00 floor/$11.07 ceiling
April 2009 - October 2009	Natural Gas	Physical	1,000 GJ/d	$7.08 fixed
April 2009 - October 2009	Natural Gas	Physical	1,000 mmbtu/d	U.S. $8.18 fixed

On January 1, 2007 the Company adopted the new accounting standards regarding the accounting for financial instruments. Under the new standards, the Company has elected to account for its physical commodity sales contracts which were entered into and continue to be held for the purpose of delivery of production in accordance with its expected sale requirements as executory contracts on an accrual basis rather than as non-financial derivatives. Prior to adoption of the new standards, physical delivery contracts did not fall within the definition of a financial instrument and were also accounted for as executory contracts.

REVENUE

	Three Months Ended December 31			Twelve Months Ended December 31		
	2007	2006	% Change	**2007**	2006	% Change
Natural gas	**20,696**	19,277	7	**77,495**	75,523	3
Crude oil	**2,263**	1,681	35	**9,596**	9,242	4
Natural gas liquids	**2,938**	1,970	49	**9,388**	9,609	(2)
Realized gain/(loss) on financial contracts	**735**	–	–	**1,454**	(185)	–
Total	**26,632**	22,928	16	**97,933**	94,189	4

The increase in revenue for the twelve months ended December 31, 2007, over the comparative period, is attributed to the increase in production volumes and a minimal change in the realized natural gas price. For the fourth quarter, revenue increased 16 percent over the comparative period due to an 18 percent increase in production volumes offset by a 10 percent decrease in the realized natural gas price.

ROYALTIES

	Three Months Ended December 31			Twelve Months Ended December 31		
	2007	2006	% Change	**2007**	2006	% Change
Total	**4,092**	2,810	46	**14,580**	13,731	6
Per boe	**7.58**	6.13	24	**7.50**	7.20	4
Percent of total revenue	**15.4**	12.3	25	**14.9**	14.6	2

The Company pays royalties to provincial governments (Crown), freeholders, which can be individuals or companies and other oil and gas operators that own surface or mineral rights. Crown royalty rates are calculated on a sliding scale based on commodity prices and individual well production rates. Royalty rates can change due to price fluctuations or changes in production volumes on a well by well basis subject to a minimum and maximum rate restriction ascribed by the Crown. For the twelve months ended December 31, 2007, royalties as a percentage of revenue increased due to the elimination of the Alberta Royalty Tax Credit (ARTC), a tax rebate from the Alberta government for eligible crown royalties paid in the year subject to a maximum of $0.5 million in 2006. During the quarter, the royalty rate increased 25 percent over the comparable period due to increased volumes from the Bigstone area which has a higher than corporate average royalty rate. For the three and twelve months ended December 31, 2007, Delphi realized approximately $3.1 million and $10.8 million in hedging gains, included in revenue, but on which royalties are not paid. Delphi pays royalties based on the provincial reference price, not the prices received, resulting in Delphi not paying royalties on the hedging gains, consistent with the comparable periods in 2006. Delphi is expecting royalties as a percentage of revenue, before hedging, to be between 18 and 20 percent in 2008.

OPERATING EXPENSES

	Three Months Ended December 31			Twelve Months Ended December 31		
	2007	2006	% Change	**2007**	2006	% Change
Total	**4,477**	3,859	16	**17,464**	15,826	10
Per boe	**8.29**	8.42	(2)	**8.99**	8.29	8

Operating expenses on a per boe basis for the twelve months ended December 31, 2007, increased eight percent over the comparative period due to a higher level of workover and maintenance activity in Delphi's core areas. Additionally, in the first half of the year, the Company had operating cost adjustments from prior years related to several non operated properties. As expected, due to the increase in production volumes and a corporate focus on cost reduction, operating costs decreased significantly from the first half of 2007 and are expected to decrease further in 2008.

Operating costs on a per boe basis for the quarter decreased two percent over the comparative period in 2006. This reduction is a result of increased volumes from the Company's core areas of Bigstone and Hythe. Bigstone, which represents 55 percent of average production has very efficient costs of approximately $5.25 per boe.

TRANSPORTATION EXPENSES

	Three Months Ended December 31			Twelve Months Ended December 31		
	2007	2006	% Change	**2007**	2006	% Change
Total	**1,387**	1,627	(15)	**6,148**	6,455	(5)
Per boe	**2.57**	3.55	(28)	**3.16**	3.38	(7)

In British Columbia, infrastructure is owned by Spectra Energy that enables natural gas producers to avoid facility construction in exchange for regulated gathering, processing and transmission fees. This all-in charge is included in transportation expenses.

On a per boe basis, transportation costs for the three and twelve months ended December 31, 2007 decreased 28 and seven percent respectively over the comparative periods. The decrease is attributed to higher production volumes with fixed firm service commitment fees for production and lower transportation costs at Hythe, Alberta than the Bigfoot area. Effective November 1, 2007 Delphi transferred a portion of its excess processing and transmission capacity to third party producers resulting in further reductions in transportation costs. Delphi expects transportation costs for 2008 to be consistent with or slightly less than the fourth quarter of 2007.

GENERAL AND ADMINISTRATIVE

	Three Months Ended December 31			Twelve Months Ended December 31		
	2007	2006	% Change	**2007**	2006	% Change
General and administrative costs	**2,319**	1,339	73	**6,957**	5,498	27
Overhead recoveries	**(196)**	(137)	43	**(711)**	(1,081)	(34)
Salary allocations	**(688)**	(413)	67	**(2,550)**	(2,045)	25
Net	**1,435**	789	82	**3,696**	2,372	56
Per boe	**2.66**	1.72	55	**1.90**	1.24	53

On a per boe basis, general and administrative (G&A) costs for the twelve months ended December 31, 2007 increased 53 percent over the comparative period in 2006. The increase is due to decreased overhead recoveries and increased office rent and direct personnel costs. As a result of high levels of activity for Delphi and for the industry as a whole, the costs associated with hiring, compensating and retaining employees and consultants have risen. Delphi is committed to continue delivering strong growth and believes a strong technical team is paramount to achieve this goal. Delphi expanded its team in 2007 with the addition of a VP Operations, a senior exploitation engineer and two senior geologists. For 2008, Delphi is expecting G&A per boe to decrease slightly as additional production volumes are achieved.

STOCK-BASED COMPENSATION

	Three Months Ended December 31			Twelve Months Ended December 31		
	2007	2006	% Change	**2007**	2006	% Change
Total	**552**	317	74	**1,297**	2,491	(48)
Per boe	**1.02**	0.69	48	**0.67**	1.31	(49)

Stock-based compensation expense is the amortization over the vesting period of the fair value of stock options granted to employees, directors and key consultants of the Company. The fair value of all options granted is estimated at the date of grant using the Black-Scholes option pricing model. The non-cash compensation expense for the twelve months ended December 31, 2007, decreased 48 percent due to the cancellation of certain stock options in which the Company recognized the unvested portion of the stock-based compensation. In addition, the Company granted 4.5 million stock options to employees, officers, and key consultants under the existing stock option plan. During the three and twelve months ended December 31, 2007, Delphi capitalized $0.6 million and $1.4 million of stock-based compensation associated with exploration and development activities.

INTEREST

	Three Months Ended December 31			Twelve Months Ended December 31		
	2007	2006	% Change	**2007**	2006	% Change
Total	**1,491**	2,026	(26)	**7,561**	6,254	21
Per boe	**2.76**	4.42	(38)	**3.89**	3.28	19

In 2007, interest costs increased 21 percent due to higher interest rates, Part XII.6 tax associated with the flow-through financing in 2006 and higher average debt levels. The Part XII.6 tax is a monthly finance charge payable to the Canada Revenue Agency until flow-through obligations have been satisfied. For the three months ended December 31, 2007, interest costs were 38 percent lower than the comparative period due to lower average debt levels and lower Part XII.6 tax. Delphi anticipates interest per boe will continue to decrease in 2008 as average debt levels remain constant and additional production is brought on stream.

DEPLETION, DEPRECIATION AND ACCRETION

	Three Months Ended December 31			Twelve Months Ended December 31		
	2007	2006	% Change	**2007**	2006	% Change
Depletion and depreciation	**13,960**	11,090	26	**48,962**	39,727	23
Accretion expense	**185**	173	7	**638**	637	–
Total	**14,145**	11,263	26	**49,600**	40,364	23
Per boe	**26.20**	24.58	7	**25.53**	21.15	21

Depletion, depreciation, and accretion per boe for the three and twelve months ended December 31, 2007 increased seven and 21 percent due to higher cost proved reserve additions. With the recently completed Hythe transaction and success at Bigstone and Noel, Delphi is in an excellent position to add proved reserves at metrics below the Company's current depletion rate. The increase in total depletion and depreciation versus the comparative periods is a result of increased production levels and a higher per boe rate.

Accretion expense of asset retirement obligations relates to the passing of time until the Company estimates it will retire its assets and restore the asset locations to a condition which meets or exceeds environmental standards. Due to the long term nature of certain assets of the Company, this accretion expense is estimated to extend over a term of three to 20 years. The Company uses a credit adjusted risk-free rate of eight percent for the purpose of calculating the fair value of its asset retirement obligations and hence the accretion expense. The accretion expense for the twelve months ended December 31, 2007 remained consistent with the comparative period.

GOODWILL

Goodwill, at the time of acquisition, represents the excess of purchase price of a business over the fair value of net assets acquired. Goodwill is assessed by the Company for impairment at least each year end. If the fair value of the business is less than the book value, a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the business' assets and liabilities from the fair value of the business to determine the implied fair value of goodwill and comparing that amount to the book value of goodwill. Any excess of the book value of goodwill over the implied fair value is the impairment amount and is charged to earnings in the period of the impairment.

The Company reviewed the valuation of goodwill as at March 31, 2007 based on the latest

available information including the market capitalization of the Company as indicated by the Company's share price at that time. Based upon this review, an impairment of goodwill of $12.1 million was recorded as a non-cash charge to earnings in the first quarter of 2007. The Company notes the write-down is a non-cash charge and does not believe it is an indication of the ultimate underlying value of the Company's assets.

TAXES

	Three Months Ended December 31			Twelve Months Ended December 31		
	2007	2006	% Change	**2007**	2006	% Change
Current	**3**	–	–	**3**	–	–
Future (reduction)	**(3,608)**	295	–	**(3,279)**	786	–
Total	**(3,605)**	295	–	**(3,276)**	786	–
Per boe	**(6.68)**	0.64	–	**(1.69)**	0.41	–

The provision for income taxes in the financial statements for the three and twelve months ended December 31, 2007, differs from the result that would have been obtained by applying the combined federal and provincial tax rates to the Company's loss before tax, primarily due to the impairment of goodwill. Although the Company records the loss for accounting purposes, it is unable to claim the loss for tax purposes currently. Delphi does not anticipate it will be cash taxable until 2009 or later based on current commodity prices.

FUNDS FROM OPERATIONS

	Three Months Ended December 31			Twelve Months Ended December 31		
	2007	2006	% Change	**2007**	2006	% Change
Net earnings	**1,732**	290	497	**(10,472)**	6,903	–
Non-cash items:						
Depletion, depreciation and accretion	**14,145**	11,263	26	**49,600**	40,364	23
Impairment of goodwill	**–**	–		**12,100**	–	–
Unrealized gain on risk management activities	**926**	(348)	–	**(765)**	(993)	(23)
Stock-based compensation expense	**552**	317	74	**1,297**	2,491	(48)
Future income taxes (reduction)	**(3,608)**	295	–	**(3,279)**	786	–
Funds from operations	**13,747**	11,817	16	**48,481**	49,551	(2)

For the three and twelve months ended December 31, 2007 funds from operations were $13.7 million ($0.20 per basic share) and $48.5 million ($0.72 per basic share) compared to $11.8 million ($0.19 per basic share) and $49.6 million ($0.85 per basic share) in 2006.

Funds from operations is a non-GAAP measure and has been defined by the Company as net earnings plus the addback of non-cash items (depletion, depreciation and accretion, stock-based compensation, future income taxes and unrealized gain/(loss) on risk management activities) and excludes the change in non-cash working capital related to operating activities and expenditures on asset retirement obligations and reclamation. Management uses funds from operations to analyze performance and considers it a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments and to repay debt.

The following table shows the reconciliation of funds from operations to cash flow from operating activities for the periods noted:

	Three Months Ended December 31			Twelve Months Ended December 31		
	2007	2006	% Change	**2007**	2006	% Change
Funds from operations: Non-GAAP	**13,747**	11,817	16	**48,481**	49,551	(2)
Settlement of asset retirement obligations	**(93)**	(98)	(5)	**(550)**	(503)	9
Change in non-cash working capital	**7,040**	(2,223)	–	**11,135**	3,102	259
Cash flow from operating activities: GAAP	**20,694**	9,496	118	**59,066**	52,150	13

NET EARNINGS/LOSS

For the three and twelve months ended December 31, 2007, Delphi recorded earnings of $1.7 million and a net loss of 10.5 million, respectively, compared to net earnings of $0.3 million and $6.9 million in the comparative periods in 2006. Earnings for the twelve month period were adversely affected by non-cash items such as depletion, depreciation, accretion, stock-based compensation, future income taxes and the impairment of goodwill. These non-cash items represent the majority of the significant difference between funds from operations and the net loss.

NETBACK ANALYSIS

	Three Months Ended December 31			Twelve Months Ended December 31		
	2007	2006	% Change	**2007**	2006	% Change
Barrels of oil equivalent ($/boe)						
Realized sales price	**49.33**	50.02	(1)	**50.41**	49.36	2
Royalties, net of ARTC	**7.58**	6.13	24	**7.50**	7.20	4
Operating expenses	**8.29**	8.42	(2)	**8.99**	8.29	8
Transportation	**2.57**	3.55	(28)	**3.16**	3.38	(7)
Operating netback	**30.89**	31.92	(3)	**30.76**	30.49	1
G&A	**2.66**	1.72	55	**1.90**	1.24	53
Interest	**2.76**	4.42	(38)	**3.89**	3.28	19
Current taxes	**0.01**	–	–	**–**	–	–
Cash netback	**25.46**	25.78	(1)	**24.97**	25.97	(4)
Unrealized (gain)/loss on financial contracts	**1.72**	(0.76)	–	**(0.39)**	(0.52)	(25)
Stock-based compensation expense	**1.02**	0.69	48	**0.67**	1.31	(49)
Depletion, depreciation and accretion	**26.20**	24.58	7	**25.53**	21.15	21
Impairment of goodwill	**–**	–	–	**6.23**	–	–
Future income taxes (reduction)	**(6.68)**	0.64	–	**(1.69)**	0.41	–
Net earnings (loss)	**3.20**	0.63	408	**(5.38)**	3.62	–

Approximately 84 percent of Delphi's production is natural gas and therefore Delphi's cash netbacks are primarily driven by the price received for natural gas.

LIQUIDITY AND CAPITAL RESOURCES

Funding

	Three Months Ended December 31, 2007	Twelve Months Ended December 31, 2007
Sources:		
Funds from operations	**13,747**	**48,481**
Disposition of petroleum and natural gas properties	**–**	**15,502**
Issue of common shares, net of issue costs	**–**	**16,882**
Cash	**847**	**757**
Change in non-cash working capital	**10,490**	**14,723**
	25,084	**96,345**
Uses:		
Capital expenditures	**16,991**	**51,924**
Acquisition of petroleum and natural gas properties	**–**	**10,871**
Expenditures on site restoration and reclamation	**93**	**550**
	17,084	**63,345**
Increase / (decrease) in bank debt	**(8,000)**	**(33,000)**

For the three and twelve months ended December 31, 2007, Delphi primarily funded its capital program through a combination of funds from operations, the issuance of flow-through common shares and funds received from the Bigfoot/Hythe swap transaction.

On March 1, 2007, Delphi issued 7,350,000 flow-through common shares at an issue price of $2.45 per common share for aggregate proceeds of $18.0 million.

Share Capital

At December 31, 2007, the Company had 68.1 million common shares outstanding (December 31, 2006 - 60.7 million). The common shares of Delphi trade on the TSX under the symbol DEE. The following table summarizes outstanding share data for the three and twelve months ended December 31, 2007.

	Three Months Ended December 31, 2007	Twelve Months Ended December 31, 2007
Weighted Average Common Shares		
Basic	**68,070**	**66,835**
Diluted	**68,070**	**66,983**
Trading Statistics		
High	**$ 1.88**	**$ 2.38**
Low	**$ 1.37**	**$ 1.32**
Average daily, volume	**123,201**	**259,574**

(1) Trading statistics based on closing price.

As at March 18, 2008 the Company had 68.4 million common shares outstanding and 5.4 milllion stock options outstanding.

Bank Debt plus Working Capital Deficit

At December 31, 2007, the Company had $82.0 million outstanding on its credit facility and a working capital deficit of $18.7 million for total debt plus working capital deficit of $100.7 million excluding the financial asset of $1.1 million relating to the unrealized gain on financial commodity contracts. Net debt levels have decreased 15 percent from December 31, 2006. Delphi anticipates spending less than projected funds from operations on capital expenditures during 2008.

The capital intensive nature of the industry will generally result in the Company having a working capital deficit. The Company has a revolving facility for $115.0 million with a syndicate of Canadian chartered banks. The facility is a 364 day committed revolving facility with a one year term out provision. The credit facility bears interest based on a sliding scale tied to the Company's trailing debt to funds from operations ratio: from a minimum of the bank's prime rate to a maximum of the bank's prime rate plus 1.0 percent. In addition to the revolving term facility, the Company has a $10.0 million development facility. The pricing grid on the development facility is 0.25 percent higher than the revolving term facility.

CONTRACTUAL OBLIGATIONS

The Company has a 364 day committed revolving credit facility with a syndicate of Canadian chartered banks which is available until April 30, 2008, the term out date. The term out date may be extended for an additional 364 days upon approval by the banks. Following the term out date, the facilities would become non-revolving for a one year term, at which time the balance outstanding would be due and payable. The Company believes the term will be extended for an additional 364 day period by April 30, 2008.

Delphi has firm contracts for gathering, processing and transmission of natural gas in British Columbia. The Company has several leases for compression equipment in the field and a lease for office space in Calgary, Alberta.

The future minimum commitments are as follows:

	2008	2009	2010	2011	2012
Bank debt (1)	–	82,000	–	–	–
Gas transmission and treatment	3,500	3,573	3,530	3,187	1,699
Office lease	582	589	603	609	623
Operating leases on field equipment	35	–	–	–	–
Total	4,117	86,162	4,133	3,796	2,322

(1) Based on the existing terms of the credit facility, however, the Company believes the term will be extended for an additional 364 day period by April 30, 2008, the term out date.

As at December 31, 2007, the Company had incurred the necessary qualifying exploration expenditures to satisfy the terms of the flow-through shares issued in 2006. Although the Company believes it has incurred the necessary qualifying expenditures, these amounts may be subject to audit and subsequent interpretation by the Canada Revenue Agency. The Company has an obligation to incur an additional $14.5 million in qualifying exploration expenditures by December 31, 2008 to satisfy the obligation relating to the issuance of flow-through shares in 2007.

GUARANTEES AND OFF-BALANCE SHEET ARRANGEMENTS

Delphi has not entered into any guarantees or off-balance sheet arrangements except for certain lease agreements entered into in the normal course of operations. All leases are operating leases with lease payments charged to operating expenses or general and administrative expenses according to the nature of the lease.

CRITICAL ACCOUNTING ESTIMATES

Delphi's financial statements have been prepared in accordance with Canadian general accepted accounting principles. Certain accounting policies require management to make decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Delphi's management reviews its estimates frequently, however, the emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ

materially from current estimates. Delphi attempts to mitigate this risk by employing individuals with the appropriate skill set and knowledge to make reasonable estimates, developing internal reporting systems and comparing past estimates to actual results.

The Company's financial and operating results include estimates of the following:

- Depletion, depreciation and accretion and the ceiling test are based on estimates of oil and gas reserves;
- Estimated revenues, operating expenses and royalties for which actual revenues and costs have not been received;
- Estimated capital expenditures on projects that are in progress;
- Estimated fair value of derivative contracts;
- Estimated amount of the asset retirement obligation including estimates of future costs and the timing of the costs; and
- Estimated fair value of the Company in performing the goodwill impairment test.

CHANGES IN ACCOUNTING POLICIES AND FILING REQUIREMENTS

Internal Control over Financial Reporting

On March 30, 2007, the Canadian Securities Administrators published a replacement for Multilateral Instrument 52-109 Certification of Disclosure in Issuer's Annual and Interim Filings (MI 52-109). The proposed National Instrument 52-109 (NI 52-109) represents an approach designed to balance the costs associated with internal control reporting and certification requirements with the benefit from increasing management's focus on, and accountability for, the quality of Internal Controls over Financial Reporting (ICOFR). The significant changes will cause certifying officers, the CEO and CFO, to certify in the annual certificates that they have evaluated the effectiveness of ICOFR at the financial year end and that they have disclosed in the annual MD&A their conclusions about the effectiveness of ICOFR. There is also no requirement to evaluate the effectiveness of the ICOFR against a suitable framework or to file management and auditor internal control audit reports regarding the ICOFR. The proposed NI 52-109 is expected to be effective December 31, 2008. Delphi will continue with its evaluation of ICOFR to ensure it meets the requirements for proposed certification effective December 31, 2008.

Financial Instruments

Effective January 1, 2007, the Company adopted the new Canadian accounting standards Section 3855 - Financial Instruments – Recognition and Measurement; Section 3861 - Financial Instruments – Presentation and Disclosure, Section 3865 – Hedges and Section 1530 - Comprehensive Income. The standards require all financial instruments other than held-to-maturity investments, loans and receivables and other financial liabilities to be included on the balance sheet at fair value. Held-to-maturity investments, loans and receivables and other financial liabilities are measured at their amortized cost. These standards also create a new Statement of Comprehensive Income for the changes in the fair value of derivative financial instruments. The Company has adopted these standards retrospectively. The adoption of these standards had no effect on opening retained earnings or accumulated other comprehensive income.

The Company adopted Section 1506 – Accounting Changes, the effect of which is to provide disclosure of when an entity has not applied a new source of GAAP that has been issued but is not yet effective. This is the case with Section 3862 – Financial Instruments – Disclosures, and Section 3863 – Financial Instruments – Presentation which are required to

be adopted for fiscal years beginning on or after October 1, 2007. The Company did adopt these standards on January 1, 2008.

Capital Disclosures

Effective December 31, 2007 Delphi adopted Section 1535, the new recommendations of the CICA for disclosure of the Company's objectives, policies and processes for managing capital. See note 7 of the Company's audited financial statements.

International Financial Reporting Standards

On February 13, 2008, Canada's Accounting Standards Board confirmed January 1, 2011 as the effective date for the convergence of Canadian GAAP to International Financial Reporting Standards. Delphi will continue to monitor the progress of the Canadian Securities Administrators plan for transition. Due to the extended period of time until implementation, Delphi has not yet determined the effects on its financial position or results of operations.

CORPORATE GOVERNANCE

Overview

The shareholders' interests are a critical factor in the operation and management of Delphi. The Company is committed to maintaining the highest level of investor confidence in the Company through the application of its corporate governance policies. Delphi's Board consists of five independent directors and two officers of the Company who meet regularly to discuss matters of strategy and execution of the business plan. See Delphi's Management Information Circular and AIF for a listing of committees that oversee specific aspects of the Company's operating and financial strategy.

Disclosure Controls and Procedures

Disclosure controls and procedures have been designed to ensure information required to be disclosed by Delphi is accumulated and communicated to the Company's management as appropriate to allow timely decisions regarding disclosures. The Company's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of the end of the period covered by the annual filings, that the Company's disclosure controls and procedures provide a reasonable level of assurance that information required to be disclosed by the Company is recorded, processed, summarized and reported within the time periods specified. The controls and procedures are designed to ensure that information required to be disclosed by the Company is accumulated and communicated to the issuer's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. The Company notes that while it believes the disclosure controls and procedures provide a reasonable level of assurance that they are effective, it does not expect that the disclosure controls and procedures will prevent all errors and fraud. A control system is designed to provide reasonable, not absolute, assurance that the objectives of the control system are met.

2008 OUTLOOK

Strategy

Delphi emphasizes a full-cycle approach to its business and strives for internally generated development opportunities as a means of enhancing its production base and ultimately creating value for shareholders. Delphi's goal is to become a dominant natural gas developer and explorer focused in North West Alberta and North East British Columbia. The objective is to develop an inventory of opportunities and undeveloped land base from which production and reserves can be added independent of acquisition activity. In that regard, the Company's ability to add production through the drill bit creates a competitive

advantage over those competitors that are reliant upon acquisitions to build or maintain their production base. Currently, Delphi has identified over one hundred drilling locations on its core areas. Delphi continues to pursue acquisitions that will be accretive on a per share basis to cash flow, production, reserves and net asset value and which provide significant development opportunities to further enhance value.

2008 Capital Activities

The capital program for 2008 has been established at an estimated $50.0 million for the drilling of approximately 15 to 18 net wells. The Company has allocated approximately one-third of its capital to each of Bigstone and Hythe with the remaining one-third allocated to other areas throughout the year. The majority of the expenditures through the winter drilling season will be allocated to Bigstone. In the latter half of the year, the majority of the capital will be directed towards Hythe, once the technical teams have had sufficient time to evaluate the multi-zone nature of this significant land base. Positive results from the capital program, coupled with moderating industry service and equipment costs and secure financial resources, continue to be the main drivers of Delphi's capital investing decision making in the context of natural gas prices and the proposed Alberta royalty regime changes. Delphi is well positioned to internally finance its capital program through funds from operations and available bank lines, if necessary.

2008 Production Guidance

For 2008, the Company has forecast average production volumes to be in the 6,000 to 6,200 boe/d range, an increase of 15 percent over the average production volumes in 2007. First quarter production is expected to average approximately 6,000 boe/d. Further quarterly production guidance will be made available throughout the year. The volumes will continue to be dominated by natural gas production of approximately 80 to 85 percent.

Alberta Royalty Review

On September 18, 2007 the Royalty Review Panel, comprised of independent members appointed by the Government of Alberta, released its report outlining recommendations on how the Government of Alberta should modify the existing royalty structure on oil and gas production. On October 25, 2007, the Government of Alberta responded by announcing its proposed changes to the royalty structure which are to be made effective January 1, 2009. The proposed recommendations would revise the royalty calculation formula for conventional oil and gas, increasing the sensitivity of royalties to both commodity prices and well productivity rates. A simplification of the overall royalty regime was also part of the recommendations including the elimination of oil and gas tiers, the elimination of a number of special royalty programs and expanded royalty rate limits on both oil and gas commodity prices. The Government of Alberta also introduced a deep gas drilling adjustment for wells greater than a certain measured depth. The Company will continue to monitor the status of the recommendations as the final royalty structure is established.

ADDITIONAL INFORMATION

Additional information about Delphi is available on the Canadian Securities Administrators' System for Electronic Distribution and Retrieval (SEDAR) at www.sedar.com, at the Company's website at www.delphienergy.ca or by contacting the Company at Delphi Energy Corp. Suite 300, 500 – 4th Avenue S.W., Calgary, Alberta, T2P 2V6 or by e-mail at info@delphienergy.ca.

Basis of Presentation. *For the purpose of reporting production information, reserves and calculating unit prices and costs, natural gas volumes have been converted to a barrel of oil equivalent (boe) using six thousand cubic feet equal to one barrel. A boe conversion ratio of 6:1 is based upon an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion conforms with the Canadian Securities Administrators' National Instrument 51-101 when boes are disclosed. Boes may be misleading, particularly if used in isolation.*

NON GAAP Measures. *The MD&A contains the terms "funds from operations", "funds from operations per share" and "netbacks" which are not recognized measures under Canadian generally accepted accounting principles. The Company uses these measures to help evaluate its performance. Management considers netbacks an important measure as it demonstrates its profitability relative to current commodity prices. Management uses funds from operations to analyze performance and considers it a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments and to repay debt. Funds from operations has been defined by the Company as net earnings plus the addback of non-cash items (depletion, depreciation and accretion, stock-based compensation, future income taxes and unrealized gain/(loss) on risk management activities) and excludes the change in non-cash working capital related to operating activities and expenditures on asset retirement obligations and reclamation. The Company also presents funds from operations per share whereby amounts per share are calculated using weighted average shares outstanding consistent with the calculation of earnings per share. Delphi's determination of funds from operations may not be comparable to that reported by other companies nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP.*

Forward-Looking Statements. *This management discussion and analysis contains forward-looking statements and forward-looking information within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", may", "will", "should", believe", "intends", "forecast", "plans", "guidance" and similar expressions are intended to identify forward-looking statements or information.*

More particularly and without limitation, this management discussion and analysis contains forward looking statements and information relating to the Company's risk management program, petroleum and natural gas production, future funds from operations, capital programs, commodity prices, costs and debt levels. The forward-looking statements and information are based on certain key expectations and assumptions made by Delphi, including expectations and assumptions relating to prevailing commodity prices and exchange rates, applicable royalty rates and tax laws, future well production rates, the performance of existing wells, the success of drilling new wells, the capital availability to undertake planned activities and the availability and cost of labour and services.

Although the Company believes that the expectations reflected in such forward-looking statements and information are reasonable, it can give no assurance that such expectations will prove to be correct. Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results may differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, the risks associated with the oil and gas industry in general such as operational risks in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of estimates and projections relating to production rates, costs and expenses, commodity price and exchange rate fluctuations, marketing and transportation, environmental risks, competition, the ability to access sufficient capital from internal and external sources and changes in tax, royalty and environmental legislation. Additional information on these and other factors that could affect the Company's operations or financial results are included in reports on file with the applicable securities regulatory authorities and may be accessed through the SEDAR website www.sedar.com. The forward-looking statements and information contained in this press release are made as of the date hereof for the purpose of providing the readers with the Company's expectations for the coming year. The forward-looking statements and information may not be appropriate for other purposes. Delphi undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

REPORTING OUR PERFORMANCE

MANAGEMENT'S REPORT

The financial statements of Delphi Energy Corp. were prepared by management in accordance with Canadian generally accepted accounting principles. The financial and operating information presented in this annual report is consistent with that shown in the financial statements. Management has designed and maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded and to facilitate the preparation of financial statements for reporting purposes. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. Such estimates are based on careful judgments made by management. External auditors appointed by the shareholders have conducted an independent examination of the Company's accounting records in order to express their opinion on the financial statements. The Board of Directors is responsible for ensuring that management fulfils its responsibilities for financial and internal control. The Board exercises this responsibility through its Audit & Reserves Committee. The Audit & Reserves Committee, which consists of non-management members, has met with the external auditors and management in order to determine that management has fulfilled its responsibilities in the preparation of the financial statements. The Audit & Reserves Committee has reported its findings to the Board of Directors who have approved the financial statements.

David Reid

David J. Reid
President and Chief Executive Officer

B Kol

Brian P. Kohlhammer
Vice President Finance and Chief Financial Officer

Calgary, Canada
March 19, 2008

AUDITORS' REPORT

We have audited the consolidated balance sheets of Delphi Energy Corp. as at December 31, 2007 and 2006 and the consolidated statements of earnings/(loss), comprehensive income/(loss) and retained earnings and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2007 and 2006, and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Calgary, Canada
March 19, 2008

CONSOLIDATED BALANCE SHEETS

As at December 31

($ thousands)	**2007**	2006
ASSETS		
Current assets		
Cash	–	757
Accounts receivable	**12,604**	16,097
Prepaid expenses and deposits	**2,752**	1,460
Risk management asset (Note 9)	**1,113**	348
	16,469	18,662
Property, plant and equipment (Note 4)	**295,266**	295,906
Goodwill (Note 11)	–	12,100
Total assets	**311,735**	326,668
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	**34,014**	21,492
Long term debt (Note 5)	**82,000**	115,000
Future income taxes (Note 8)	**28,162**	23,776
Asset retirement obligations (Note 6)	**7,183**	7,951
Total liabilities	**151,359**	168,219
SHAREHOLDERS' EQUITY		
Share capital (Note 7)	**148,898**	139,108
Contributed surplus (Note 7)	**8,236**	5,627
Retained earnings	**3,242**	13,714
Total shareholders' equity	**160,376**	158,449
Total liabilities and shareholders' equity	**311,735**	326,668

Commitments (Note 10)

See accompanying notes to the consolidated financial statements.

Approved by the Board of Directors,

H.R. Lawrie

Henry R. Lawrie
Director

L. Tolley

Lamont C. Tolley
Director

CONSOLIDATED STATEMENTS OF EARNINGS/(LOSS), COMPREHENSIVE INCOME/(LOSS) AND RETAINED EARNINGS

For the years ended December 31

($ thousands, except per unit amounts)	**2007**	2006
REVENUE		
Petroleum and natural gas sales	**96,479**	94,374
Realized gain/(loss) on risk management activities	**1,454**	(185)
	97,933	94,189
Royalties	**(14,580)**	(13,731)
Unrealized gain on risk management activities	**765**	993
	84,118	81,451
EXPENSES		
Operating	**17,464**	15,826
Transportation	**6,148**	6,455
General and administrative	**3,696**	2,372
Stock-based compensation (Note 7)	**1,297**	2,491
Interest	**7,561**	6,254
Depletion, depreciation and accretion	**49,600**	40,364
Impairment of goodwill (Note 11)	**12,100**	–
	97,866	73,762
Earnings/(loss) before taxes	**(13,748)**	7,689
TAXES (Note 8)		
Current	**3**	–
Future/(reduction)	**(3,279)**	786
	(3,276)	786
Net earnings/(loss) and comprehensive income/(loss)	**(10,472)**	6,903
Retained earnings, beginning of year	**13,714**	6,811
Retained earnings, end of year	**3,242**	13,714
Net earnings/(loss) per share (Note 7)		
Basic	**(0.16)**	0.12
Diluted	**(0.16)**	0.12

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31

($ thousands)	**2007**	2006
CASH FLOW FROM OPERATING ACTIVITIES		
Net earnings/(loss)	**(10,472)**	6,903
Add non cash items:		
Depletion, depreciation and accretion	**49,600**	40,364
Impairment of goodwill (Note 11)	**12,100**	–
Stock-based compensation	**1,297**	2,491
Unrealized gain on risk management activities	**(765)**	(993)
Future taxes (reduction)	**(3,279)**	786
Expenditures on asset retirement obligations	**(550)**	(503)
Change in non-cash working capital (Note 12)	**11,135**	3,102
	59,066	52,150
CASH FLOW FROM FINANCING ACTIVITIES		
Issue of common shares, net of issue costs	**16,882**	23,583
Increase/(decrease) in bank debt	**(33,000)**	73,300
	(16,118)	96,883
CASH FLOW USED IN INVESTING ACTIVITIES		
Capital expenditures	**(51,924)**	(165,352)
Acquisition of petroleum and natural gas properties	**(10,871)**	–
Disposition of petroleum and natural gas properties	**15,502**	34,918
Change in non-cash working capital (Note 12)	**3,588**	(17,842)
	(43,705)	(148,276)
Increase in cash and cash equivalents	**(757)**	757
Cash and cash equivalents, beginning of year	**757**	–
Cash and cash equivalents, end of year	**–**	757
Interest paid	**7,087**	5,585
Taxes paid	**3**	220

See accompanying notes to the consolidated financial statements.

As at and for the years ended December 31, 2007 and 2006
(all tabular amounts are expressed in thousands of dollars, except per unit amounts)

NOTE 1: DESCRIPTION OF BUSINESS

Delphi Energy Corp. ("the Company" or "Delphi") is incorporated under the Business Corporations Act (Alberta) and is a public company listed on the Toronto Stock Exchange. Delphi is primarily engaged in the exploration for and development and production of natural gas properties located in North West Alberta and North East British Columbia.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of Delphi have been prepared by management in accordance with accounting principles generally accepted in Canada. The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses. Actual results may differ from these estimates.

(a) Principles of consolidation

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. Any reference to the Company refers to the Company and its subsidiaries. All inter-company transactions have been eliminated.

(b) Petroleum and natural gas operations

The Company follows the full cost method of accounting whereby all costs associated with the exploration for and development of petroleum and natural gas reserves are capitalized. Such costs include land acquisition costs, geological and geophysical costs, lease rental costs on non-producing properties, costs of both productive and unproductive drilling and production equipment. Gains or losses are not recognized upon disposition of petroleum and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the depletion rate of 20% or more.

The accumulated costs, less the costs of acquisition of unproved properties, are depleted using the unit-of-production method based upon total proved reserves before royalties as determined by independent evaluators. Natural gas reserves and production are converted into equivalent barrels of oil at 6:1 based upon the estimated relative energy content.

The costs of acquiring and evaluating unproved properties are initially excluded from depletion calculations. These properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of impairment is added to the costs subject to depletion.

The Company is required to perform a ceiling test at least annually to assess the carrying amount of oil and gas assets. The costs are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves using forecast prices and the lower of cost and market of unproved properties exceed the carrying amount of the petroleum and natural gas assets. If the carrying amount of the petroleum and natural gas assets is assessed to not be recoverable, an impairment loss is recognized to the extent that the carrying amount exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves and the lower of cost and market of unproved properties. This approach incorporates risks and uncertainties in the expected future cash flows, which are discounted using a risk free rate.

Depreciation of furniture and office equipment is provided using the declining balance method based upon estimated useful lives of 20% to 50%.

(c) Joint operations

Substantially all of the Company's exploration, development and production activities are conducted jointly with others and the financial statements reflect the Company's proportionate interest in such activities.

(d) Goodwill

Goodwill, at the time of acquisition, represents the excess of purchase price of a business over the fair value of net assets acquired. Goodwill is assessed by the Company for impairment at least each year end. If the fair value of the business is less than the book value, a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the business' assets and liabilities from the fair value of the business to determine the implied fair value of goodwill and comparing that amount to the book value of goodwill. Any excess of the book value of goodwill over the implied fair value is the impairment amount and will be charged to income in the period of the impairment.

(e) Asset retirement obligations

The Company recognizes the fair value of an asset retirement obligation as a liability at the time it incurs a legal obligation for the future abandonment and reclamation costs associated with its petroleum and natural gas operations. Asset retirement obligations are initially measured at their fair value and subsequently adjusted to reflect the passage of time (accretion) and any changes to the estimated cash flows underlying the obligation. The associated asset retirement cost is capitalized as part of property, plant and equipment and amortized to earnings using the unit of production method over estimated proved reserves consistent with the depletion and depreciation of the underlying asset.

(f) Stock-based compensation

The Company records a compensation cost for all stock options granted to employees, directors or key consultants over the vesting period of the options based on the fair value method. The compensation cost is a charge to earnings or capitalized as a cost of exploration and development activities with an offsetting increase to contributed surplus on the balance sheet. Consideration paid by employees, directors or key consultants upon exercise of the stock options and the amount previously recognized in contributed surplus are recorded as share capital. The Company has not incorporated an estimated forfeiture rate for stock options that will not vest, rather, the Company accounts for actual forfeitures as they occur.

(g) Future income taxes

The Company follows the tax liability method of accounting for income taxes. Under this method, estimated future income tax assets and liabilities are determined based upon differences between the carrying amount as reported on the balance sheet and the tax basis of assets and liabilities and measured using substantively enacted tax rates and laws expected to be in effect when the differences are expected to reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in earnings in the period in which the change occurs. A valuation allowance is recognized against any future income tax assets if it is considered more likely than not that the asset will not be realized.

(h) Flow-through shares

The resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. To recognize the foregone tax benefits to the Company, the future income tax liability and share capital are adjusted by the estimated cost of the renounced tax deduction on the date of renouncement.

(i) Per share information

Basic per share amounts are computed by dividing the net earnings by the weighted average number of common shares outstanding for the year. Diluted per share amounts reflect the potential dilution that would occur if securities or other contracts to issue common shares were exercised or converted to common shares. Diluted per share information is calculated using the treasury stock method that assumes any proceeds received by the Company upon the exercise of in-the-money stock options, plus the unamortized stock based compensation cost, would be used to buy back common shares at the average market price for the period. Anti-dilutive options or instruments are not included in the calculation.

(j) Financial instruments

Effective January 1, 2007, the Company adopted the new Canadian accounting standards for financial instruments – recognition and measurement; financial instruments – presentation and disclosure, hedging and comprehensive income. The Company has adopted these standards retrospectively. The adoption of these standards had no effect on opening retained earnings or accumulated other comprehensive income.

i) Financial instruments – recognition and measurement

The new standard prescribes when a financial asset, financial liability or non-financial derivative is to be recognized on the balance sheet and at what amount, requiring fair value or cost-based measures under different circumstances. Financial instruments must be classified into one of the following five categories: held-for-trading, held-to-maturity, loans and receivables, available-for-sale financial assets or other financial liabilities. All financial instruments, including derivatives and non-financial derivatives are measured in the balance sheet at fair value except for loans and receivables, held-to-maturity investments and other financial liabilities which are measured at amortized cost determined using the effective interest rate method. The accounting for subsequent changes in fair value will depend on initial classification, as follows: changes in fair value of held-for-trading financial assets are recognized in net earnings; changes in fair value of available-for-sale financial instruments are recorded in other comprehensive income until the investment is derecognized or impaired at which time the amounts are recorded in net earnings.

Upon adoption of these standards, the Company classified its cash as held-for-trading which was measured at fair value. Accounts receivable were classified as loans and receivables and were measured at amortized cost. Accounts payable and long term debt were classified as other financial liabilities and were measured at amortized cost.

ii) Derivatives

All derivative instruments, including embedded derivatives, are recorded on the balance sheet at fair value unless exempted from derivative treatment as a normal purchase and sale. All changes in the fair value of derivative instruments are recorded in earnings unless cash flow hedge accounting is used, in which case changes in fair value are recorded in other comprehensive income. The Company has a risk management program whereby the commodity price associated with a portion of its future production is fixed in order to mitigate cash flow volatility resulting from fluctuating commodity prices. The Company

sells forward a portion of its future production and enters into a combination of fixed price physical sale contracts with customers and fixed price financial contracts with financial counterparties.

The Company has elected not to use cash flow hedge accounting on its fixed price contracts with financial counterparties resulting in all changes in fair value being recorded in the statement of earnings. The Company has elected to account for its physical commodity sales contracts which were entered into and continue to be held for the purpose of delivery of production in accordance with its expected sale requirements as executory contracts on an accrual basis rather than as non-financial derivatives. Prior to adoption of the new standards, physical receipt and delivery contracts did not fall within the definition of a financial instrument and were also accounted for as executory contracts.

iii) Other comprehensive income

The new standards require a new statement of comprehensive income, which is comprised of net earnings and other comprehensive income which, for the Company, relates to changes in gains or losses on derivatives designated as cash flow hedges. The Company has combined this new statement with the statement of earnings.

iv) Effective interest rate method

Transaction costs attributable to financial instruments classified as other than held-for-trading are included in the recognized amount of the related financial instrument and recognized over the term of the resulting financial instrument.

(k) Measurement uncertainty

The amounts recorded for depletion and depreciation of petroleum and natural gas properties and equipment are based upon estimates of proved petroleum and natural gas reserves, production rates, commodity prices and future costs. The impairment test is based upon estimates of proved and, if applicable, probable reserves, production rates, petroleum and natural gas prices, future costs and other assumptions. The asset retirement obligations are based upon petroleum and natural gas reserves, future costs, expected inflation rates and other assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes to estimates in future periods could be material.

(l) Cash and cash equivalents

The Company considers deposits in banks, certificates of deposit and short-term investments with original maturities of three months or less as cash and cash equivalents. Bank borrowings are considered to be financing activities.

(m) Revenue recognition

Crude oil and natural gas revenues are recognized in earnings when title passes from the Company to its customer.

NOTE 3: CHANGE IN ACCOUNTING POLICIES

Effective December 31, 2007 the Company adopted new disclosure standards with respect to capital management.

Effective January 1, 2008 new accounting standards will require additional disclosure about the Company's financial instruments to be included in the financial statements. The guidance prescribes an increased importance on risk disclosures associated with realized and unrealized financial instruments and how such risks are managed. In addition, the guidance outlines revised requirements for the disclosure of qualitative and quantitative information regarding exposure to risks arising from financial instruments.

NOTE 4: PROPERTY, PLANT AND EQUIPMENT

As at December 31, 2007	Cost	Accumulated depletion and depreciation	Net book value
Petroleum and natural gas properties	**$ 323,305**	**$ 114,408**	**$ 208,897**
Production equipment	**105,713**	**19,877**	**85,836**
Furniture, fixtures and office equipment	**1,003**	**470**	**533**
	$ 430,021	**$ 134,755**	**$ 295,266**

As at December 31, 2006			
Petroleum and natural gas properties	$ 285,168	$ 71,331	$ 213,837
Production equipment	95,892	14,087	81,805
Furniture, fixtures and office equipment	639	375	264
	$ 381,699	$ 85,793	$ 295,906

On September 12, 2007 Delphi closed a transaction whereby the Company's 50 percent working interest in the Bigfoot area in North East British Columbia was exchanged for certain assets in the Hythe area located in North West Alberta and $15.1 million in cash.

As at December 31, 2007, costs in the amount of $10.8 million (December 31, 2006 - $35.8 million) representing unproved properties were excluded from the depletion calculation and estimated future development costs of $15.7 million (December 31, 2006 - $21.7 million) have been included in costs subject to depletion. All costs of unproved properties have been capitalized. Ultimate recoverability of these costs will be dependent upon finding proved oil and natural gas reserves. The Company performed a separate impairment review of assets excluded from depletion and determined that no impairment has occurred.

The Company capitalized $2.3 million (December 31, 2006 - $1.8 million) of general and administrative costs directly related to exploration and development activities.

The Company performed a ceiling test calculation at December 31, 2007 to assess the recoverable value of property, plant and equipment, which indicated no write down was required. The future commodity prices used in the impairment test were based on December 31, 2007 commodity price forecasts of the Company's independent reserve engineers adjusted for differentials specific to the Company's reserves. The following table summarizes the future benchmark prices the Company used in the impairment test.

	Natural Gas		Natural Gas Liquids			Crude Oil		
	Henry Hub	AECO Spot	Propane	Butane	Pentanes Plus	West Texas Intermediate	Edmonton Light	Bow River Hardisty
	(US$/mmbtu)	(CDN$/mmbtu)	(CDN$/bbl)	(CDN$/bbl)	(CDN$/bbl)	(US$/bbl)	(CDN$/bbl)	(CDN$/bbl)
2008	7.40	6.75	58.30	72.88	92.92	92.00	91.10	63.77
2009	8.20	7.55	55.74	69.68	88.84	88.00	87.10	60.97
2010	8.25	7.60	53.18	66.48	84.76	84.00	83.10	58.17
2011	8.35	7.60	51.90	64.88	82.72	82.00	81.10	56.77
2012	8.35	7.60	51.90	64.88	82.72	82.00	81.10	56.77
2013	8.35	7.60	51.90	64.88	82.72	82.00	81.10	57.58
2014	8.55	7.80	51.90	64.88	82.72	82.00	81.10	58.39
2015	8.72	7.97	51.90	64.88	82.72	82.00	81.10	59.20
2016	8.89	8.14	51.91	64.89	82.74	82.02	81.12	60.03
2017	9.06	8.31	52.97	66.21	84.42	83.66	82.76	61.24
Thereafter (1)								

(1) A percentage increase of 2% represents the change in future prices each year after 2017 to the end of the reserve life.

NOTE 5: LONG TERM DEBT

The Company has a revolving facility for $115.0 million with a syndicate of Canadian chartered banks. The facility is a 364 day committed revolving facility with a one year term out provision. The credit facility bears interest based on a sliding scale tied to the Company's trailing debt to cash flow: from a minimum of the bank's prime rate to a maximum of the bank's prime rate plus 1.0 percent.

In addition to the revolving term facility, the Company has a $10.0 million development facility with its lenders. The pricing grid on the development facility is 0.25 percent higher than the revolving term facility.

The two facilities are secured by a $200.0 million demand floating charge debenture and a general security agreement over all assets of the Company.

NOTE 6: ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations result from working interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations, over the next three to twenty years, is approximately $16.3 million. A credit-adjusted risk-free rate of 8.0 percent and an inflation rate of 2.5 percent were used to calculate the estimated fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below.

As at December 31	2007	2006
Balance, beginning of year	**$ 7,951**	$ 7,394
Liabilities incurred	**1,017**	606
Liabilities disposed	**(1,873)**	(183)
Liabilities settled	**(550)**	(503)
Accretion expense	**638**	637
Balance, end of year	**$ 7,183**	$ 7,951

NOTE 7: SHARE CAPITAL

(a) Authorized

An unlimited number of common shares.

An unlimited number of preferred shares issuable in series.

(b) Common shares issued

	2007		2006	
As at December 31	**Outstanding shares (000's)**	**Amount**	Outstanding shares (000's)	Amount
Balance, beginning of year	**60,663**	**$ 139,108**	55,254	$ 123,692
Issue of flow-through common shares	**7,350**	**18,007**	5,209	25,003
Exercise of stock options	**57**	**83**	200	305
Allocated from contributed surplus	**–**	**39**	–	145
Share issue costs	**–**	**(1,208)**	–	(1,725)
Future tax effect of share issue costs	**–**	**369**	–	528
Tax benefit renounced to shareholders	**–**	**(7,500)**	–	(8,840)
Balance, end of year	**68,070**	**$ 148,898**	60,663	$ 139,108

On March 1, 2007, the Company issued 7.35 million flow-through common shares at a price of $2.45 per share for gross proceeds of $18.0 million.

On June 29, 2006, the Company issued 5.2 million flow-through common shares at a price of $4.80 per share for gross proceeds of $25.0 million.

The Company has incurred the necessary qualifying exploration expenditures to satisfy the terms of the flow-through shares issued in 2006. Although the Company believes it has incurred the necessary qualifying expenditures, these amounts may be subject to audit and subsequent interpretation by the Canada Revenue Agency. The Company has an obligation to incur qualifying exploration expenditures of $18.0 million by December 31, 2008 to satisfy the obligation relating to the issuance of flow-through shares in 2007, of which $14.5 million remains to be incurred as at December 31, 2007.

(c) Stock options

The Company has established a stock option plan under which it has granted options to acquire common shares to certain officers, directors, employees and key consultants. The plan provides for the granting of options equal to ten percent of the issued and outstanding common shares of the Company. Options issued under the plan have a term of five years to expiry and vest over a two-year period starting on the date of the grant. The exercise price of each option equals the 5 day weighted average of the closing market price of the Company's common shares, immediately preceding the date of the grant. As at December 31, 2007 there were 5.5 million options to purchase shares outstanding.

The following table summarizes the changes in the number of options outstanding and the weighted average share prices.

	2007		2006	
As at December 31	**Outstanding options (000's)**	**Weighted average exercise price**	Outstanding options (000's)	Weighted average exercise price
Balance, beginning of year	**4,229**	**$ 3.40**	2,629	$ 2.37
Granted	**4,500**	**1.67**	1,800	4.69
Cancelled	**(121)**	**3.92**	–	–
Forfeited	**(3,070)**	**4.09**	–	–
Exercised	**(57)**	**1.45**	(200)	1.53
Balance, end of year	**5,481**	**$ 1.60**	4,229	$ 3.40
Exercisable at end of year	**2,481**	**$ 1.52**	2,641	$ 2.81

The following table summarizes information about the stock options outstanding and exercisable at December 31, 2007.

	Options outstanding			Options exercisable	
Range of exercise price	Outstanding Options (000's)	Weighted average exercise price	Weighted average remaining term (years)	Exercisable (000's)	Weighted average exercise price
$ 0.99	**344**	**$ 0.99**	**0.2**	**344**	**$ 0.99**
$ 1.45 – 1.79	**5,122**	**1.64**	**4.0**	**2,132**	**1.61**
$ 1.80 – 2.00	**15**	**1.93**	**4.5**	**5**	**1.93**
Total	**5,481**	**$ 1.60**	**4.0**	**2,481**	**$ 1.52**

(d) Stock-based compensation

The Company accounts for its stock-based compensation using the fair value method for all stock options. For the year ended December 31, 2007 Delphi recorded non-cash compensation expense of $1.3 million. The Company capitalized $1.3 million (December 31, 2006 - $0.9 million) of stock-based compensation directly related to exploration and development activities.

The fair values of all options granted during the period are estimated at the date of grant using the Black-Scholes option pricing model. The weighted average fair value of options granted during the period was $0.96 per share. The assumptions used in the Black-Scholes model to determine fair value were as follows:

Year ended December 31	**2007**	2006
Risk free interest rate (%)	**5.0**	5.0
Expected life (years)	**5.0**	5.0
Expected volatility (%)	**53.0**	45.0

(e) Contributed surplus

The following table outlines the changes in the contributed surplus balance:

As at December 31	**2007**	2006
Balance, beginning of year	**$ 5,627**	$ 2,380
Stock-based compensation costs	**2,648**	3,392
Reclassification to common shares on exercise of stock options	**(39)**	(145)
Balance, end of year	**$ 8,236**	$ 5,627

(f) Net earnings/(loss) per share

Net earnings/(loss) per share has been based on the following weighted average common shares:

Year ended December 31	**2007**	2006
Basic	**66,835**	58,051
Diluted	**66,983**	58,845

The reconciling item between the basic and diluted weighted average common shares outstanding is stock options. In 2007, the majority of stock options were anti-dilutive and therefore excluded from the diluted weighted average shares outstanding.

(g) Capital management

The Company considers share capital and net debt, being the sum of long term debt and current liabilities less current assets, as the components of capital to be managed.

The Company's objective in managing its capital is to ensure adequate and appropriate sources of capital are available to execute a capital investment program while maintaining a flexible overall capital structure. Maintaining a flexible capital structure is important due to the inherent risks in oil and gas operations and the volatility of commodity prices.

The Company manages its capital structure by keeping abreast of current and forecast economic conditions and commodity prices, particularly natural gas and the cost of oilfield services. Additionally, the Company establishes internal processes to monitor and estimate planned capital expenditures, forecast funds from operations and current and forecast debt levels.

The key measure used by the Company to evaluate its capital structure is the ratio of net debt to funds from operations, defined as cash flow from operations activities before expenditures on asset retirement obligations and change in non-cash working capital. This ratio represents the time period required to repay the Company's net debt from funds generated from operations on the assumption there are no further capital expenditures incurred and funds from operations remain constant. The measure is often calculated on a historic annual basis and on an annualized most recent quarter basis to provide a more current view of the Company's capital structure.

At December 31, 2007 net debt, excluding risk management assets or liabilities, was $100.7 million and funds from operations was $48.5 million resulting in a net debt to funds from operations ratio of 2.1 times, down from 2.4 times at December 31, 2006. On an annualized fourth quarter 2007 basis, funds from operations would be $55.0 million resulting in a net debt to funds from operations ratio of 1.8 times. The Company is focused on achieving its internal target range for this ratio of 1.3 to 1.5 times.

The Company maintains an active risk management program as an integral part of its capital management strategy to mitigate the volatility in funds from operations resulting from fluctuating commodity prices. The net debt to funds from operations ratio will be the key driver in determining whether to maintain or alter the capital structure. To alter the capital structure of the Company consideration would be given to the level of credit available under current banking facilities, the proceeds on disposition of properties, the amount of the planned capital expenditure program and the offering of new common share equity if available on favourable terms.

NOTE 8: TAXES

(a) Expected tax rate

The provision for income taxes in the financial statements differs from the result that would have been obtained by applying the combined federal and provincial tax rates to the Company's earnings before taxes.

The difference results from the following items:

Year ended December 31	**2007**	2006
Earnings (loss) before income taxes	**$ (13,748)**	$ 7,689
Statutory tax rate	**32.46%**	34.74%
Expected income tax expense	**(4,463)**	2,671
Crown charges	**–**	126
Resource allowance	**–**	(4)
Alberta royalty tax credit	**–**	(74)
Stock-based compensation	**421**	865
Attributed Canadian Royalty Income (ACRI)	**96**	(226)
Reduction in future income tax rates	**(3,634)**	(3,019)
Impairment of goodwill	**3,928**	–
Other	**376**	447
Total taxes	**$ (3,276)**	$ 786

(b) Future tax liability

The tax effect of temporary differences that give rise to significant portions of the future tax assets and liabilities at December 31, 2007 and 2006 are presented below:

As at December 31	2007	2006
Future income tax assets:		
Asset retirement obligations	**$ 1,885**	$ 2,385
ACRI	**270**	367
Risk management asset	**(332)**	(121)
Non capital losses	**4,142**	–
Share issue costs	**1,160**	1,569
Future income tax liabilities:		
Property, plant and equipment	**(35,287)**	(27,976)
Net future income tax liability	**$ (28,162)**	$ (23,776)

NOTE 9: FINANCIAL INSTRUMENTS

(a) Commodity price risk management

The Company has a price risk management program whereby the commodity price associated with a portion of its future production is fixed. The Company sells forward a portion of its future production and enters into a combination of fixed price sale contracts with customers and commodity swap agreements with financial counterparties. The forward contracts are subject to market risk from fluctuating commodity prices and exchange rates.

As at December 31, 2007, the Company has fixed the price applicable to future production through the following contracts:

Time Period	Commodity	Type of Contract	Quantity Contracted	Contract Price ($/unit)
November 2007 – March 2008	Natural Gas	Physical	3,000 GJ/d	$9.00 floor/$9.98 ceiling
November 2007 – March 2008	Natural Gas	Physical	2,000 mmbtu/d	U.S. $10.28 fixed
November 2007 – March 2008	Natural Gas	Physical	2,000 GJ/d	$7.75 floor/$9.03 ceiling
November 2007 – March 2008	Natural Gas	Physical	2,000 GJ/d	$8.00 floor/$10.02 ceiling
November 2007 – March 2008	Natural Gas	Financial	1,500 GJ/d	$8.55 fixed
November 2007 – March 2008	Natural Gas	Physical	1,500 GJ/d	$8.55 fixed

The Company entered into the following contracts subsequent to December 31, 2007:

Time Period	Commodity	Type of Contract	Quantity Contracted	Contract Price ($/unit)
April 2008 – October 2008	Natural Gas	Physical	2,000 mmbtu/d	U.S. $8.00 fixed
April 2008 – October 2008	Natural Gas	Financial	1,000 GJ/d	$8.07 fixed
April 2008 – October 2008	Natural Gas	Financial	1,000 GJ/d	$8.07 fixed
April 2008 – October 2008	Natural Gas	Financial	1,000 GJ/d	$7.75 floor/$9.55 ceiling
April 2008 – October 2008	Natural Gas	Physical	2,000 GJ/d	$7.82 fixed
November 2008 – March 2009	Natural Gas	Physical	2,000 GJ/d	$7.62 fixed
November 2008 – March 2009	Natural Gas	Physical	2,000 mmbtu/d	U.S. $9.00 fixed
November 2008 – March 2009	Natural Gas	Financial	1,000 GJ/d	$8.00 floor/$11.07 ceiling
April 2009 – October 2009	Natural Gas	Physical	1,000 GJ/d	$7.08 fixed
April 2009 – October 2009	Natural Gas	Physical	1,000 mmbtu/d	U.S. $8.18 fixed

(b) Fair value of financial instruments

The fair values of financial assets and liabilities that are included in the balance sheet approximate their carrying amounts due to bank debt being at a floating interest rate and other financial assets and liabilities have a short term to maturity.

(c) Credit risk

Substantially all of the Company's accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. With respect to counterparties to financial instruments, the Company partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

(d) Foreign currency exchange risk

The Company is exposed to foreign currency fluctuations as crude oil and natural gas prices are referenced to U.S. dollar denominated prices.

(e) Interest rate risk

The Company is exposed to interest rate risk to the extent that bank debt is at a floating rate of interest.

NOTE 10: CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The Company is committed to future minimum payments for natural gas transmission and processing and operating leases on compression equipment and office space. The Company's extendible term credit facility is available on a revolving basis until April 30, 2008, the term out date. The term out date may be extended for a further 364 day period upon approval by the banks. Following the term out date, the facilities would be available on a non-revolving basis for a one year term. The Company believes the term will be extended for an additional 364 day period. Without assuming the renewal of the credit facilities, payments required under these commitments for each of the next five years are: 2008-$4.1 million; 2009-$86.2 million; 2010-$4.1 million; 2011-$3.8 million; 2012-$2.3 million.

NOTE 11: GOODWILL

The Company reviewed the valuation of goodwill as of March 31, 2007 based upon the latest available information including the market capitalization of the Company as indicated by the Company's share price. Based upon this review, an impairment of goodwill of $12.1 million was recorded as a non-cash charge to earnings in the first quarter of 2007.

NOTE 12: CHANGES IN NON-CASH WORKING CAPITAL ITEMS

Year ended December 31	**2007**	2006
Change in working capital item:		
Accounts receivable	**$ 3,493**	$ 1,810
Prepaid expenses and deposits	**(1,292)**	9,710
Accounts payable and accrued liabilities	**12,522**	(26,260)
Total change in non-cash working capital	**14,723**	(14,740)
Relating to:		
Operating activities	**11,135**	3,102
Financing activities	**–**	–
Investing activities	**3,588**	(17,842)
	$ 14,723	$ (14,740)

CORPORATE INFORMATION

Directors

David J. Reid
President and Chief Executive Officer
Delphi Energy Corp.

Tony Angelidis
Senior Vice President Exploration
Delphi Energy Corp.

Harry S. Campbell, Q.C. (2)
Partner
Burnet, Duckworth & Palmer LLP

Henry R. Lawrie (1)
Independent Businessman

Robert A. Lehodey, Q.C. (2)
Partner
Osler, Hoskin & Harcourt LLP

Andrew E. Osis (1)
Chief Financial Officer and Director
Multiplied Media Corporation

Lamont C. Tolley (1)
Independent Businessman

(1) Member of the Audit & Reserves Committee
(2) Member of the Corporate Governance and Compensation Committee

Officers

David J. Reid
President and Chief Executive Officer

Tony Angelidis
Senior Vice President Exploration

Hugo H. Batteke
Vice President Operations

Rod A. Hume
Vice President Engineering

Michael S. Kaluza
Chief Operating Officer

Brian P. Kohlhammer
Vice President Finance and
Chief Financial Officer

Corporate Office

300, 500 - 4th Avenue S.W.
Calgary, Alberta
T2P 2V6

Telephone: (403) 265-6171
Facsimile: (403) 265-6207
Email: info@delphienergy.ca
Website: www.delphienergy.ca

Auditors

KPMG LLP

Bankers

National Bank of Canada
The Bank of Nova Scotia

Legal Counsel

Osler, Hoskin & Harcourt LLP

Independent Engineers

GLJ Petroleum Consultants Ltd.

Transfer Agent

Olympia Trust Company

Stock Exchange Listing

Toronto Stock Exchange - DEE

Annual General Meeting

May 22, 2008, Calgary, Alberta

designed and produced by nonfiction studios inc.

Delphi Energy Corp.

PEOPLE
OPPORTUNITY
GROWTH